Parsons Infrastructure & Technology Group Report No. **EJ-2001-05**
DOE Contract Number DE-AM26-99FT40465 / Task 50901: Market and Environmental Analysis
Parsons Job / WBS: 736223 / 00100

Final Report

GEMSET Special Assessment:

The Economics of Gas Turbines in the PJM Region

August 2001

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The United States Department of Energy
National Energy Technology Laboratory

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Technical Report Abstract

Parsons Infrastructure & Technology Group Inc.

Strategic Center for Natural Gas

EJ-2001-05

How Natural Gas Price Affects the Addition of New Gas Turbines

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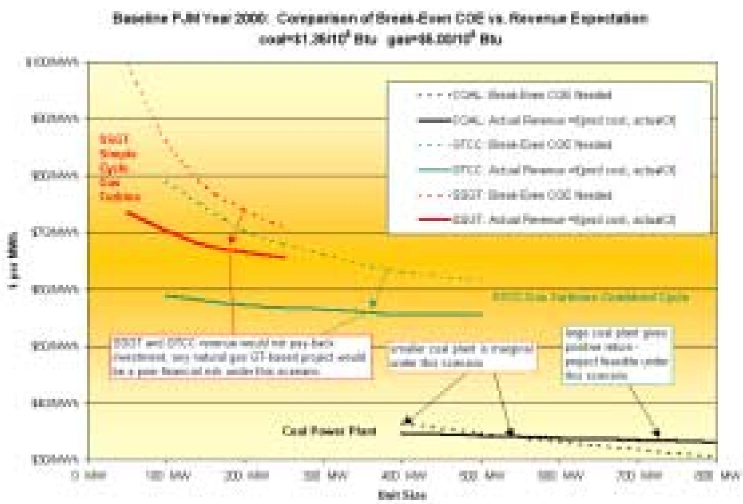
Generating company owners take significant risk when they invest their money in new electric generation equipment. Two important factors affect the ability of the owner to make a profit on a new electric generating unit. One is how well the owner evaluates how much demand there will be for the sale of electricity from the new generation unit, and the other is how much it will cost to operate.

Gas turbines and combined cycle units use jet engines specially designed to generate electricity. These are the most frequently ordered types of electric generation plants today. They use natural gas as a fuel, so natural gas price is one of the most factors that affect their cost of operation.

In December 1999 the delivered cost of natural gas to generation company owners in the mid-Atlantic region averaged \$3.37/million Btu. (A Btu is a measure of the heat release from burning gas). In one year, by December 2000, this rose to \$6.40/million Btu. This dramatic rise in price is a great concern to generating company owners, as it directly affects profitability.

The Strategic Center for Natural Gas thus posed these questions: How important is the price of natural gas in the decision to purchase either gas turbines or combined cycles? At what price threshold would generating company owners seek other types of generation fuels?



Significance

The money needed to buy a gas turbine for electric power generation is substantial. An owner might risk \$38,000,000 to build a 100 megawatt gas turbine plant to meet electric needs during peak demand periods, or $195,000,000 to build a 400 megawatt

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report title:

The Economics of Gas Turbines in the PJM Region

Key Services

- Characterize all PJM Units
- Estimate how PJM electric price would change under different fuel cost scenarios
- Evaluate characteristics of gas turbines and combined cycles of various sizes
- Estimate economics of GTs under the various scenarios

Study Region

PJM generating units: Pennsylvania, New Jersey, Maryland DC, Delaware

Contract / Job Numbers

DE-AM26-99FT40465
Task 50901
Parsons: 736223 / 00100

combined cycle. When making a decision about investing this amount of money, good judgment about potential fuel cost is important, because a significant amount of money is at stake. Higher-than-expected fuel price can lose money until fuel price drops or electric sale price rises, or the project could even fail financially. Similarly, if apprehension about profit from such a large investment causes the potential owner to cancel or abandon development of a new plant, needed units might not be built; there might be inadequate generation to meet demand growth in a region, resulting in electric power shortages and skyrocketing electric price to consumers during peak demand periods.

Approach

The SCNG evaluated the economics of natural-gas-fueled gas turbines, and combined cycles in the largest competitive market region in the United States - the Pennsylvania, New Jersey, Maryland (PJM) interconnect. SCNG developed a range of possible future fuel price situations to evaluate potential impacts on the financial prospects for gas turbines and combined cycles under different circumstances. The evaluation predicted the economic return for generating units under those fuel price scenarios. Some features of this study include the following:

- The production cost of each existing generating unit within PJM was estimated.
- Fuel prices within the region were assessed, and the likely range of different price circumstances was evaluated in five study scenarios. Variations of both natural gas and coal prices were evaluated.
- A sophisticated evaluation method characterized PJM's hour-by-hour electric price under this range of fuel price scenarios, using a different generating fleet stacking order for each scenario. These anticipated how the competitive PJM market might react to such changes.
- The potential hour-by-hour sale price of electricity was evaluated for each scenario as it was affected by the entire fleet of units presently operating in the PJM region. The amount of time a unit would be called on for operation was assessed, and the potential income to the generating unit owner evaluated.
- The study evaluated a range of gas turbine, combined cycle, and pulverized coal plant of different sizes to find the threshold in fuel price where one or the other made sense.

Results

The sophisticated assessment is described in this report which gives an in-depth assessment of results. The study shows that as long as natural gas price persists below about $4.00/million Btu, investors will continue to find it profitable to invest in new gas turbine and combined cycle electric generation projects.

This evaluation provided competitive market evaluation experts to develop solidly based conjecture about how fuel price changes might affect day-ahead prices in the PJM region. A thorough assessment of 497 generating units in PJM was developed, and the fuel consumption and economics of this fleet were characterized. This allowed the development of a stacking order for the units on the basis of their present operating cost circumstances. The altered threshold bid prices for the fleet under the several fuel price scenarios allowed the re-stacking of this threshold bid price order.

PJM's price structure was analyzed, and the potential return to investors from day-ahead electric prices developed. From this, the nature of the competitive market was inferred. A sophisticated model was established of the region that then allowed a reasoned conjecture about how the price structure of PJM might change under differing demand and fuel price circumstances. This allowed the projection of day-ahead electricity price, and assessment of the potential financial income and capacity factor of a unit that hoped to compete for electric sales within the PJM region.

Using this extensively documented evaluation, the project team was able to project the prices and capacity factors that would result under each scenario's circumstances. This established a basis for assessing how each scenario's circumstance might influence the economics of gas turbines and combined cycles versus the economics of potential competing new pulverized coal power plant projects. These were evaluated over a range of plant sizes.

Ordinarily a market assessment project of this depth and sophistication could not be accomplished at this low budget level. However, the extensive base of prior information developed from similar assessments of PJM allowed this project to be accomplished quickly and economically.

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ACKNOWLEDGMENTS

This report was prepared for **the United States Department of Energy's National Energy Technology Laboratory**. This work was completed under the support of DOE Contract Number DE-AM26-99FT40465. This was performed as Task 50901: "Market and Environmental Analysis." The authors wish to acknowledge the excellent cooperation of DOE NETL, particularly:

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Substantial amounts of supporting information came from the National Energy Technology Laboratory (NETL). The authors wish to acknowledge the excellent cooperation of DOE NETL, particularly:

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Abbreviations and Acronyms

Term	Meaning
COE	in economic sections: the cost of electricity, the levelized busbar cost of electric production including amortized capital, operating, and maintenance costs
combustion turbine, CT	a synonym for gas turbine, used interchangeably
DOE	United States Department of Energy
ECAR	East Central Area Reliability Coordination Agreement, one of the NERC regions
EFORd	demand equivalent forced outage rate
eGADS	electronic generator availability data system; an electronic data system allowing the posting of data regarding a generating unit's availability record
EIA	the Energy Information Administration of the DOE
EPRI	the Electric Power Research Institute
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, one of the NERC regions
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization, a sulfur emission control device
FOB	free on board
FRCC	Florida Reliability Coordinating Council,
GADS	generator availability data system; see "eGADS"
gas turbine, GT	a synonym for combustion turbine, used interchangeably
GEMSET	an acronym for "Government Energy Market Segment Evaluation Tool"
GNP	gross national product
GT	gas turbine (a synonym for combustion turbine)
GTCC	natural gas fueled gas turbine combined cycle
HHV	higher heating value of a fuel including the heat released if all of the water vapor in the combustion products were condensed
IPP	an independent power producer, an unregulated electric generating company
IRP	integrated resource plan

ISO....................................independent system operator; a regulated body that dispatches all competitive electric generation on the high voltage transmission grid within its service region; they operate the grind, administer the power pools power transfers, select the lower cost generation bid into the pool according to the pool's operating rules, and maintains the integrity of the electric transmission grid

LCC....................................local control center

LHV....................................lower heating value of a fuel, the heat released if all of the water vapor in the combustion products remained as steam

LMP....................................locational marginal price

MAAC.................................Mid-Atlantic Area Council, a reliability council, a NERC region

MAIN..................................Mid-America Interconnected Network

MAPP..................................Mid-Continent Area Power Pool, a NERC region

MCR....................................maximum continuous rating

mmBtu................................10^6 British thermal units

MVA....................................megavolt amperes

MVAR.................................megavolt-ampere-reactive

MWe....................................electrical megawatts

MWth..................................thermal megawatts

NAERO...............................the North American Electric Reliability Organization; NERC is in the process of transforming itself into NAERO, whose principal mission will be to develop, implement, and enforce standards for a reliable North American bulk electric system.

NERC..................................North American Electric Reliability Council; soon, NERC will become NAERO

NETL...................................the U.S. Department of Energy's National Energy Technology Laboratory

NOPR..................................notice of proposed rulemaking

NOx.....................................nitrogen oxides, types of air pollutant, mainly NO and NO_2

NPCC..................................Northeast Power Coordinating Council, a NERC region

....non-utility generator, a competitive, unregulated independent electric power producer

OTAG..................................Ozone Transport Assessment Group

OTR....................................Northeast Ozone Transport Region

Parsons I&T, PI&T.............Parsons Infrastructure & Technology Group Inc., a global business unit of Parsons Corporation, an engineering/ construction company; part of the DOE team that prepared this report

Parson E & C, PE & C........Parsons Energy & Chemicals Group, Inc., business unit of Parsons Corporation that helped prepare this Report

PCD....................................particulate emission control device

P.E. .... licensed professional engineer

PJM .... Pennsylvania, New Jersey, Maryland, or PJM Interconnection LLC, an ISO.

PSC .... local state Public Service Commission

RACT .... reasonably available control technology (pollution control)

RMCP .... regulation market clearing price

RTO .... regional transmission owner

SERC .... Southeast Electric Reliability Council, a NERC region

SCNG .... Strategic Center for Natural Gas

SOx .... sulfur oxides, types of air pollutant, mainly SO_2

SPP .... Southwest Power Pool, a NERC region

WSCC .... Western Systems Coordinating Council

VAR .... volt-ampere-reactive

1. Summary

This is a report about the economics of natural gas fueled gas turbines, and gas turbine combined cycles in the PJM region, under a range of possible future fuel price situations. The evaluation gives a reasonable range of economic return expected from units that might operate on the PJM interconnection, the largest competitive electric market in the U.S. This report provides the background about how fuel price versus plant size data was developed, in response to a request for this information from the NETL Strategic Center for Natural Gas.

PJM Interconnection, LLC. (PJM) is the largest centrally dispatched electric control area in North America, and the third largest in the world. Only the control regions of the country of France and those for Tokyo Electric in Japan dispatch more megawatts of electric generation. Established in 1927, PJM today handles the dispatch of over 56,000 megawatts of electric capacity, controlling the generation of 535 units serving areas located mostly in Pennsylvania, New Jersey, Maryland, and parts of Virginia, Delaware, and the District of Columbia.

With the implementation of the PJM Open Access Transmission Tariff on April 1, 1997, PJM began operating the nation's first regional bid-based energy market. PJM enables participants to buy and sell energy, schedule bilateral electric sale transactions, and reserve transmission service. PJM provides the accounting and billing services for these transactions. PJM's operations are a model for many other regions contemplating —or recently converted to— bid-based electric market operations.

This report provides conjecture about how fuel price changes might affect day-ahead prices in the PJM region, and how the prices and capacity factors might influence the economics of gas turbines and combined cycles versus the economics of pulverized coal power plants.

The economics investigated in this report are confined to "energy only" unit revenue streams. A generating company owner may choose to accept PJM constraints in exchange for additional revenue. While not discussed here, that added revenue could be obtained by offering the unit as a "capacity" unit, or selling ancillary services. Accepting the revenue for these latter types of service offerings place very significant obligations on the generating unit owner, since these services provide electrical grid reliability for PJM.

Exhibit 1-1 summarizes the principal economic results of this evaluation for simple cycle gas turbines evaluated under the price structures that existed in Year 2000 in PJM. Exhibit 1-2 does the same for combined cycles. Exhibit 1-1 and Exhibit 1-2 show that for today's day-ahead prices for electricity, and today's $5.00/10^6 Btu natural gas price, it is not possible to recover the investment in a new gas turbine peaker or combined cycle. Either the price in the region must increase, or gas price must be lower for such projects to prove profitable. Only larger coal plants would prove profitable at these prices. These results are detailed later, in Section 6, "Modeling the PJM Generation Fleet Under Different Fuel Scenarios."

Exhibit 1-1
Summary of Economics of Simple Cycle Gas Turbines vs. Size in PJM

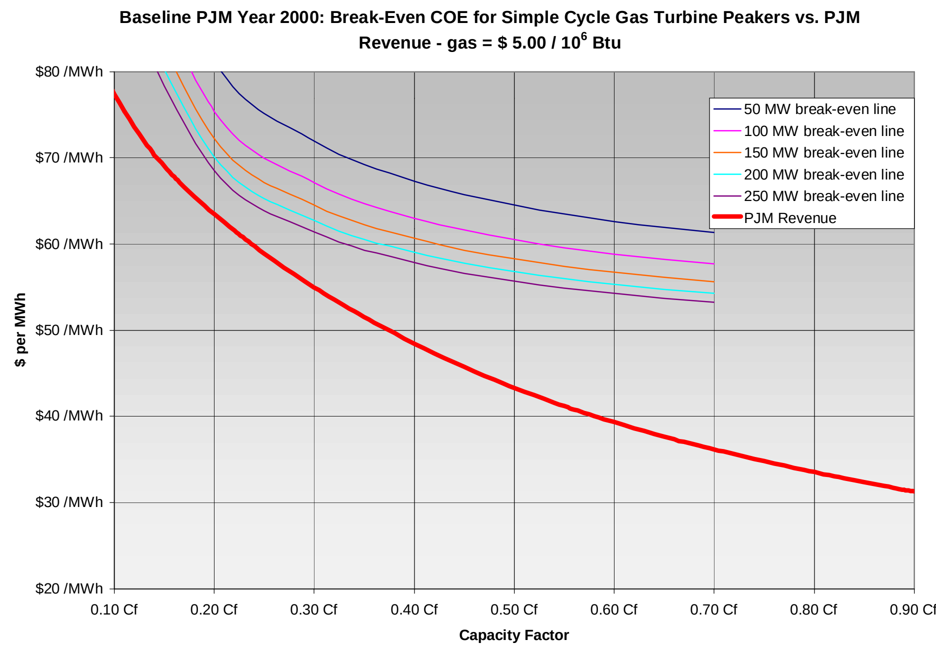
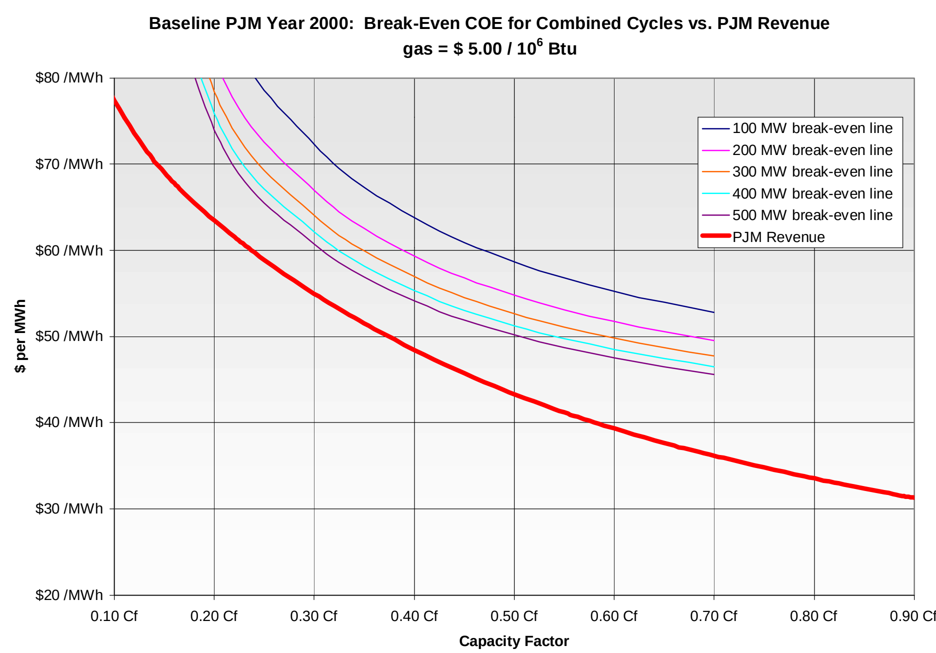


Exhibit 1-2
Summary of Economics of Combined Cycles vs. Size in PJM



It is believed that the PJM electric price is undervalued under today's threshold bid prices unless natural gas price drops soon. If Year 2000 gas price persists; price in the region will grow, otherwise, there will be delays in adding electric supply that would that would have the same effect: delay of installation would cause supply shortages that would force that growth in price. It is evident that the price in the region will certainly rise when demand grows, since new generation must make an adequate capital recovery at an acceptable marginal cost of entry.

Comparisons vs. Natural Gas Price. The eight curves shown in Exhibit 1-3 through Exhibit 1-6 summarize the results of the study that are discussed in detail later in Sections 9 through 14.

The GEMSET methods used to evaluate electricity price and unit capacity factor approximate how generating company owners choose to bid their units into the PJM competitive market. The reader can review the capacity factor (actual kWh / [period hours * rating]) that the GEMSET team estimates would be obtained for new gas turbines and combined cycles of different output ratings. These capacity factor estimates are shown in the left-side curves included as Exhibit 1-3 through Exhibit 1-6. Each curve is the result of restacking the PJM fleet of generating units for each fuel price scenario, and estimating the electric price consequences of that restack.

- Exhibit 1-3 is for the $3.00/10^6 Btu natural gas price scenario,
- Exhibit 1-4 is for the $4.00/10^6 Btu natural gas price scenario,
- Exhibit 1-5 is for the $5.00/10^6 Btu natural gas price scenario, and
- Exhibit 1-6 is for the $8.00/10^6 Btu natural gas price scenario.

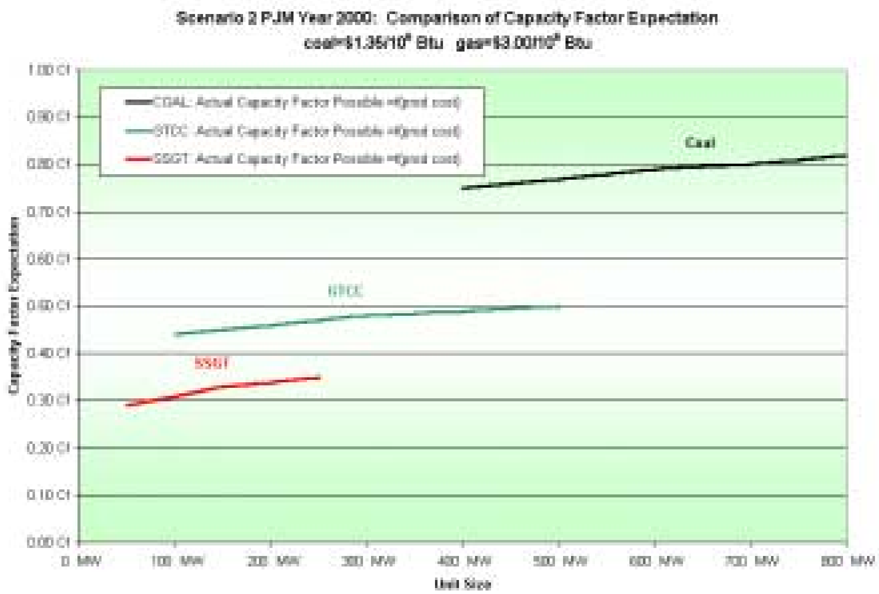
Increased natural gas price forces the owner of a potential new gas-fueled unit to evaluate the consequences of his higher production costs. With higher costs, the owner would be successful in bidding profitably for fewer hours during the year, so his unit's capacity factor would be lower because of the higher production costs forced by his increased gas price. Gas turbines and combined cycles thus show reduced capacity factor at the higher gas prices. The reduced hours of operation make it increasingly difficult to recover an adequate return on the owner's investment.

Exhibit 1-3 through Exhibit 1-6 also show the potential to recover investment, in the curves on the right-hand side. In these curves two significant factors are shown. The dashed lines show the break-even revenue needed to pay off the operating costs and capital charges. This is the zero profit line. The solid lines show the revenue that would be earned if the owner was able to bid into the market whenever the sale price of electricity was above his production costs, that is, whenever operation earned money. Operating costs are recovered, but not necessarily fixed or capital costs, unless the return is high enough.

Whenever the dashed line is below the solid line, the project investment is profitable. Operating costs are met. Fixed costs and debt are served, and all the revenue above the dashed line is before-tax profit. However, whenever the dashed line is above the solid line, operating costs are recovered, but there is insufficient revenue to recover the fixed costs or financial investment -- the project would lose money, and be unable to service it's debt.

Exhibit 1-3 Capacity Factor and Cost of Electricity versus Natural Gas Price Expected for Gas Turbines, Combined Cycles and Coal Plants in PJM ($1.35/10^6 Btu Coal and $3.00/10^6 Btu gas)

Capacity Factor	Cost of Electricity
$ 1.35 / 10^6 Btu coal -- $ 3.00 / 10^6 Btu gas	**$ 1.35 / 10^6 Btu coal -- $ 3.00 / 10^6 Btu gas**



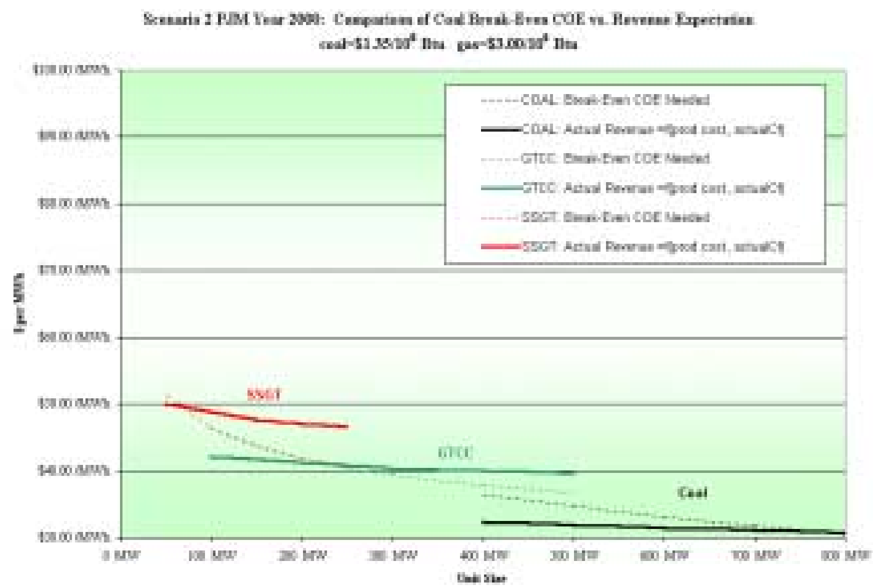


Exhibit 1-4 Capacity Factor and Cost of Electricity versus Natural Gas Price Expected for Gas Turbines, Combined Cycles and Coal Plants in PJM ($1.35/10^6 Btu Coal and $4.00/10^6 Btu gas)

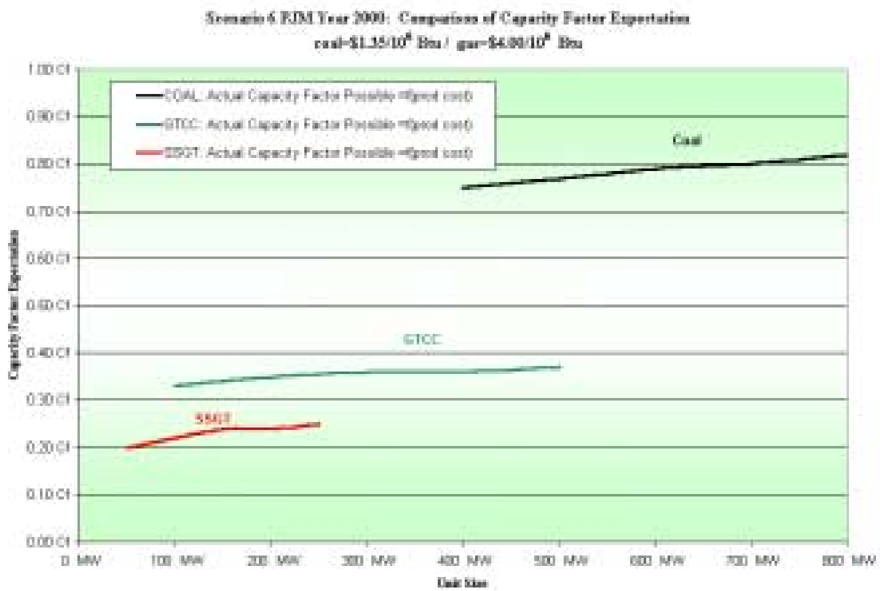
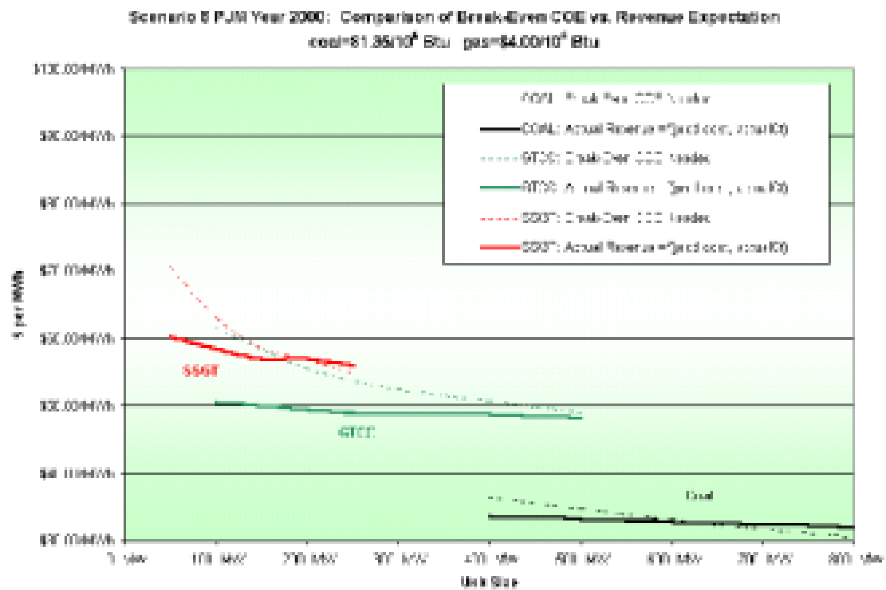
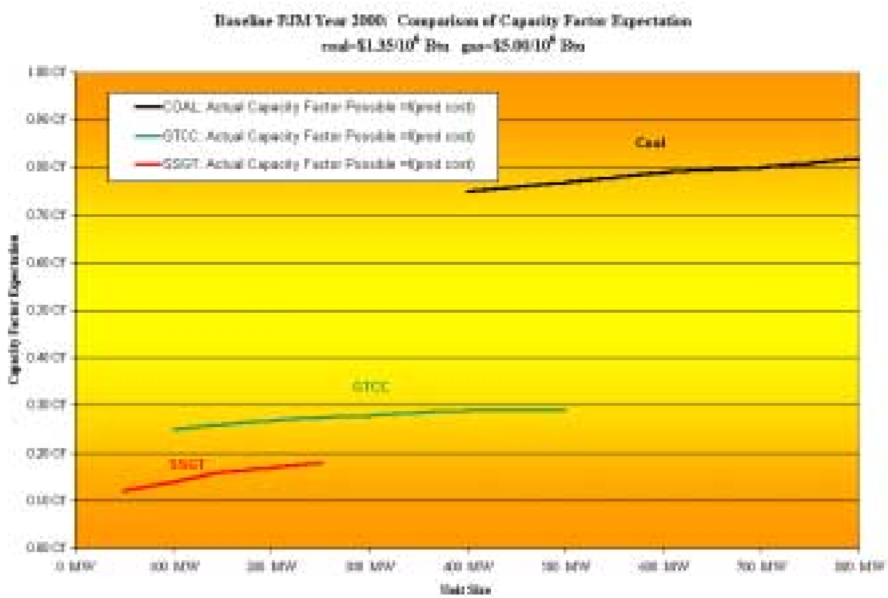
Capacity Factor	Cost of Electricity
$ 1.35 / 10^6 Btu coal -- $ 4.00 / 10^6 Btu gas	$ 1.35 / 10^6 Btu coal -- $ 4.00 / 10^6 Btu gas
	

Exhibit 1-5 Capacity Factor and Cost of Electricity versus Natural Gas Price Expected for Gas Turbines, Combined Cycles and Coal Plants in PJM ($1.35/$10^6$ Btu Coal and $5.00/$10^6$ Btu gas)

Capacity Factor	Cost of Electricity
$ 1.35 / 10^6 Btu coal -- $ 5.00 / 10^6 Btu gas	**$ 1.35 / 10^6 Btu coal -- $ 5.00 / 10^6 Btu gas**



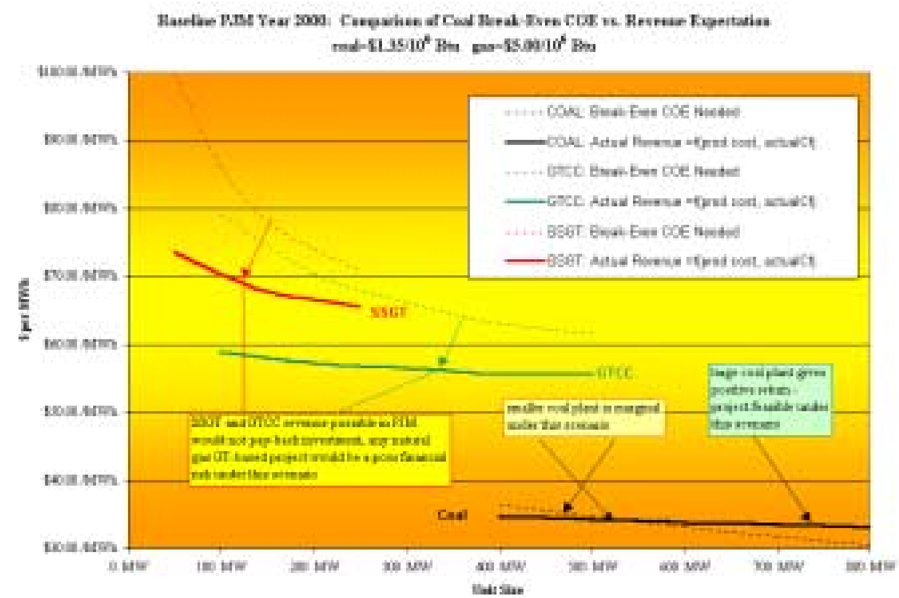
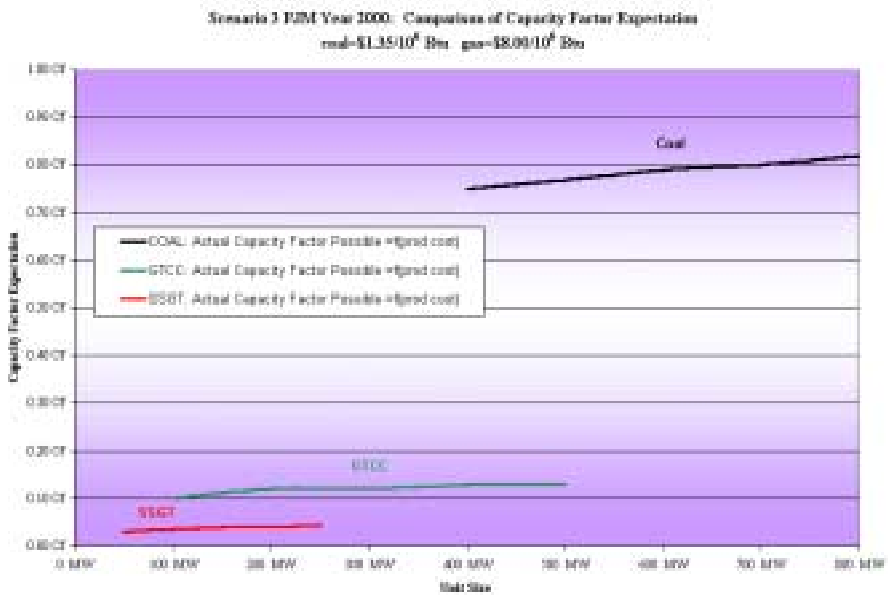


Exhibit 1-6 Capacity Factor and Cost of Electricity versus Natural Gas Price Expected for Gas Turbines, Combined Cycles and Coal Plants in PJM ($\$1.35/10^6$ Btu Coal and $\$8.00/10^6$ Btu gas)

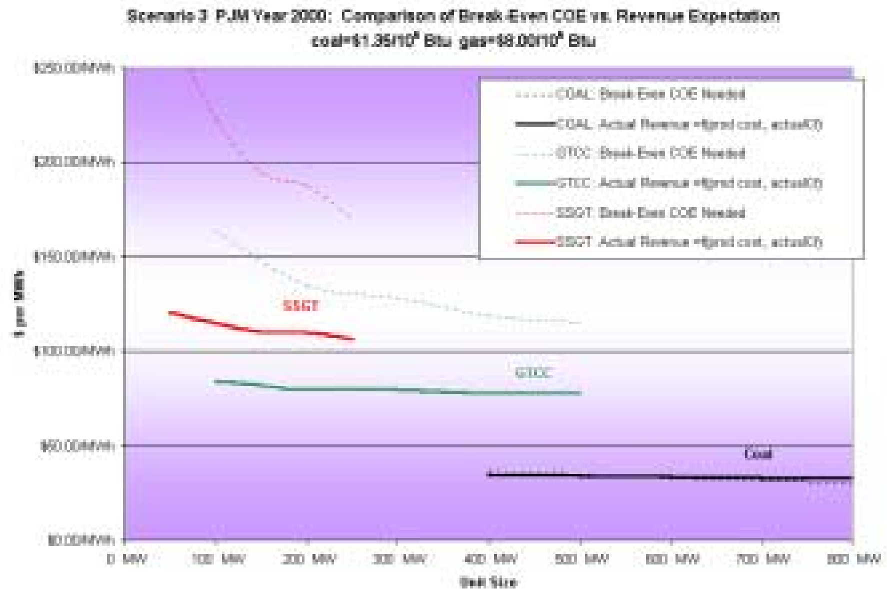
Capacity Factor

$ 1.35 / 10^6 Btu coal -- $ 8.00 / 10^6 Btu gas



Cost of Electricity

$ 1.35 / 10^6 Btu coal -- $ 8.00 / 10^6 Btu gas



The right-hand-side curves in Exhibit 1-3 through Exhibit 1-6 show the GEMSET estimates of the prospects for gas turbines, combined cycles, and coal plants under several natural gas price scenarios. These curves are estimated for today's generation fleet in PJM with the current demand level in the region. In each of these scenarios, the coal price is fixed at $1.35/$10^6$ Btu; later sections explore other situations. At $3.00/$10^6$ Btu natural gas price in PJM, new coal projects are not expected to prove a profitable investment choice. Larger combined cycle projects and gas turbine projects would make money, and be a better investment choice. Were gas prices to persist above $4.00/$10^6$ Btu, coal projects make better investments, while neither combined cycle nor gas turbine projects are would make sense.

What You Will Find In This Report. The sections that follow in this report document the procedures used to develop these curves, and provides a number of related curves that assist in understanding the results of this endeavor. These sections include the following discussions:

- This study focuses on one region of the United States. Section 2, "PJM Region Historical Data," describes the wholesale energy price structure of the PJM region and the electrical demand of the region. The histograms that characterize the actual year 2000 price duration persistence and load duration persistence in the region are used as the basis for all of the economic projection evaluations in this report. This is the region’s historical demand and price data, with information about energy prices, generation mix, and baseload and peaking demand.

- The economics of generation can not be established without first establishing the fuel price for the generating units in the region. Section 3, "PJM Fuel Price and Financial Data Projections," discusses the basis for the fuel prices used here.

- Section 4, "Modeling the PJM Generation Fleet Under Different Fuel Scenarios," then describes the methods used for projecting the operating economics of units in PJM under the several study scenarios investigated.

- Section 5, "PJM Market Study Assumptions," then gives the basis of assumptions used to characterize the region's prices under the different scenarios.

- Section 6, "PJM Unit Data," describes the units that comprise the existing generation capability in PJM. The output and estimated threshold bid price of these units is used to stack the presumed dispatch order of generation in the region. The stacking is based on the Year 2000 fuel costs and known or presumed heat rates of these units.

- Section 7, "PJM Threshold Bid Price and Price Projections Under the Different Study Scenarios," gives a review of the expectation of price and revenue made from the above procedures. These curves are the basis for the economic projections made under each scenario in the later results sections.

- Section 8, "Overview of Results," gives a series of tabulations that compare each scenario in an overview of the study. These results are discussed and detailed later individually in Sections 9 through 14 that follow.

- Sections 9 through 14 give the forecasts and projections on price under varying fuel price scenarios under these assumptions. Since the fuel price is different, the stacking order of the PJM units in the fleet differs for each scenario, as does the expected day-ahead price structure that is expected to result. The five scenarios evaluated include the following:

  - ✔ Section 9 describes "PJM MARKET STUDY RESULTS - Scenario 1: PJM At Present: Coal \$1.35 /10^6 Btu Gas \$5.00/10^6 Btu,"

  - ✔ "PJM MARKET STUDY RESULTS - Scenario 2: Coal \$1.35/10^6 Btu Gas \$3.00/10^6 Btu" is discussed in Section 10;

  - ✔ "PJM MARKET STUDY RESULTS - Scenario 6: Coal \$1.35/10^6 Btu Gas \$4.00/10^6 Btu" is discussed in Section 11

  - ✔ "PJM MARKET STUDY RESULTS - Scenario 3: Coal \$1.35/10^6 Btu Gas \$8.00/10^6 Btu" is discussed in Section 12;

  - ✔ "PJM MARKET STUDY RESULTS - Scenario 4: Coal \$2.00/10^6 Btu Gas \$5.00/10^6 Btu" is discussed in Section 13; and, finally

  - ✔ "PJM MARKET STUDY RESULTS - Scenario 5: PJM As Is With Coal At \$1.35/10^6 Btu and Gas \$5.00/10^6 Btu, but Local Unit Has Lower-Priced Gas \$3.00/10^6 Btu" is discussed in Section 14.

- Finally, a 5-Year Forecast of the PJM Market, based on the Baseline Scenario is presented in Section 15.

The references used to prepare the various sections of this report are listed in Section 16 at the end of the report.

2. PJM Region Historical Data

This section discusses the characterization of the Pennsylvania, New Jersey, Maryland regional segmentation used in the DOE GEMSET market analysis model. This region is served by a single ISO. PJM is one of the best examples of a region operating as a competitive electric market, and is significantly different from other regions, particularly those still using a regulated utility operations environment, where new generation options are approved by a commission or regulatory body. Instead, under a competitive market like that in PJM, new generation is at more of a risk than a regulated market. New generation here is met by investors seeking profit due to sale price opportunities, and their perception of persistence of electric sales price in the region remaining sufficiently above their threshold bid prices to prove profitable.

In the PJM region, most of the electric sales are pre-arranged by bilateral agreements, with the rest sold on the day-ahead or hour-ahead markets, which provide the market signals that guide and limit the value of the private bilateral sales.

Readers wishing more information on the region should review the Characterization of the PJM Region report[1], from which these data are excerpted.

2.1 The Independent System Operator: PJM Interconnection

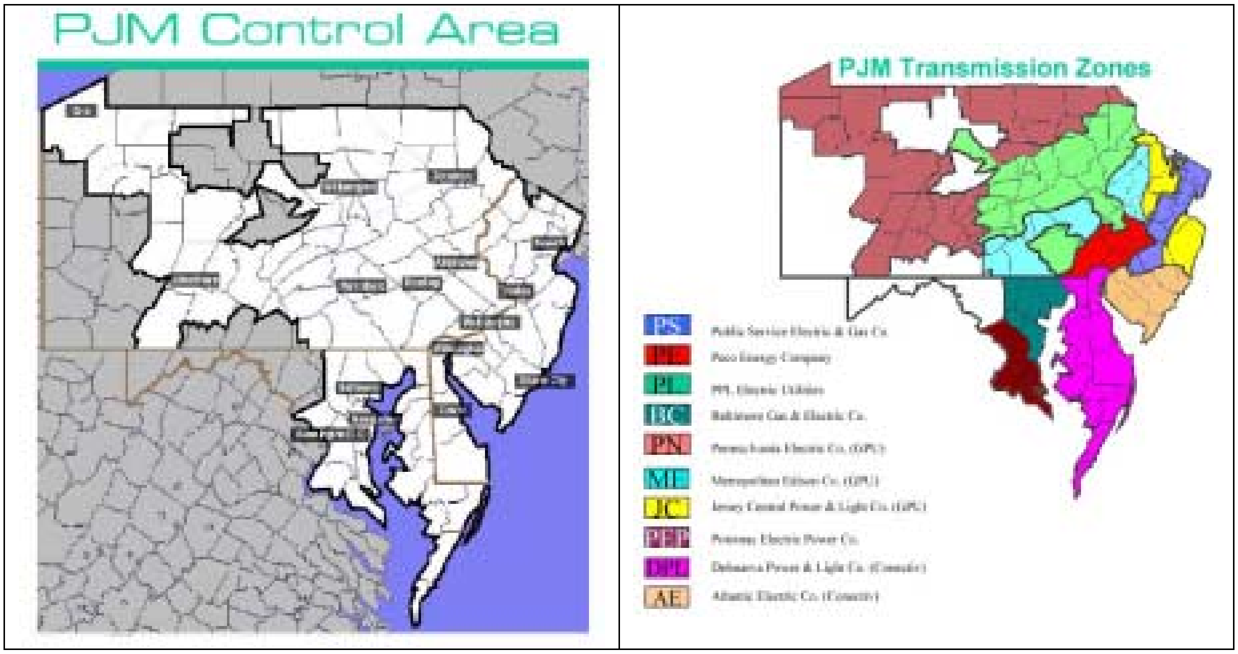
The Pennsylvania, New Jersey and Maryland (PJM) region's electric power is dispatched competitively. The independent system operator (ISO) for this region is PJM Interconnection, LLC. In addition to generation provided by the local distribution company, which had generation resources, and bilateral agreements for generation between a supplier and a generator, approximately 15 percent of the total requirements for electric power are done on the basis of spot market purchases.

The PJM service area includes all or part of:

- Pennsylvania,
- New Jersey,
- Maryland,
- Delaware,
- Virginia and the District of Columbia.

Six state and district regulatory commissions and the Federal Energy Regulatory Commission (FERC) have jurisdiction within the PJM control area. With over 170 members including every segment of the electric power industry, PJM characterizes its market as one of the most liquid and active energy markets in the country.

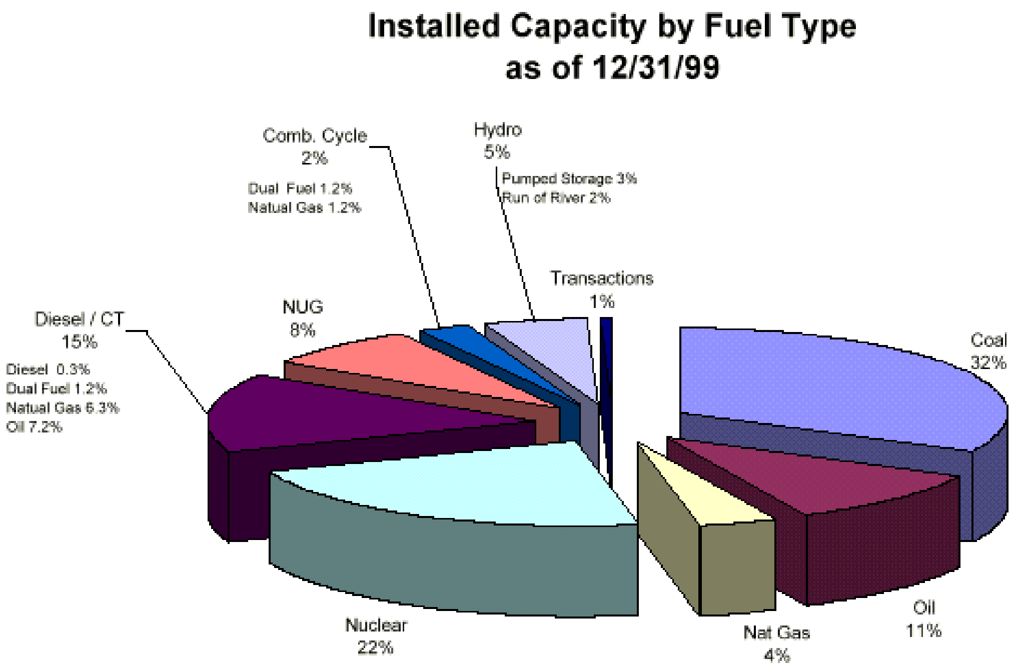
Exhibit 2-1
Map of PJM Control Area and Transmission Zones



Source: PJM[2]

2.2 Generation Mix

The installed capacity of PJM increased by 445 MW during 1999. PJM summer net installed capacity as of 12/31/99 was 57,996 MW. The short-term outlook for capacity additions sum to 19,189 megawatts by the end of 2003 based on recent studies, and listed projects in the queue process dictated by PJM. Most of the new generation additions are being supplied by non-Load Serving Entities, and are predominately combined cycle units. These new additions have been in the queue for several years, and while some have been deferred recently due to the run up in natural gas prices, those that are under construction are likely to be finished and added to the amount of generation available in PJM.



2.3 Price Duration

The curves that follow show the average hourly day-ahead prices of the PJM Zone, that is, the average prices posted for every hour over the period from January 2000 through December 2000. These data are posted by PJM Interconnection, from their Internet file transfer protocol web site: ***ftp://www.pjm.com/pub/account/lmpmonthly/index.html***.

These data are listed on an hour-by-hour basis. The GEMSET team collected these data, then sorted them into a price duration histogram for each month. The data for an entire year's span was then developed. The results of this assessment are presented in the subsections that follow.

2.4 Characterization of Year 2000 PJM Data

A composite of the month-by-month PJM day-head price data was assembled that gives one year's worth of PJM data. This is shown in Exhibit 2-2. The demand associated with these prices is shown in Exhibit 2-3. This year's worth of price data was developed into an annual price duration curve, Exhibit 2-4**.** Exhibit 2-5 shows the price demand profile for this one-year period. These data includes the pricing and demand information for the period from January 1, 2000 to December 31, 2000.

Exhibit 2-2 PJM Day-Ahead Prices

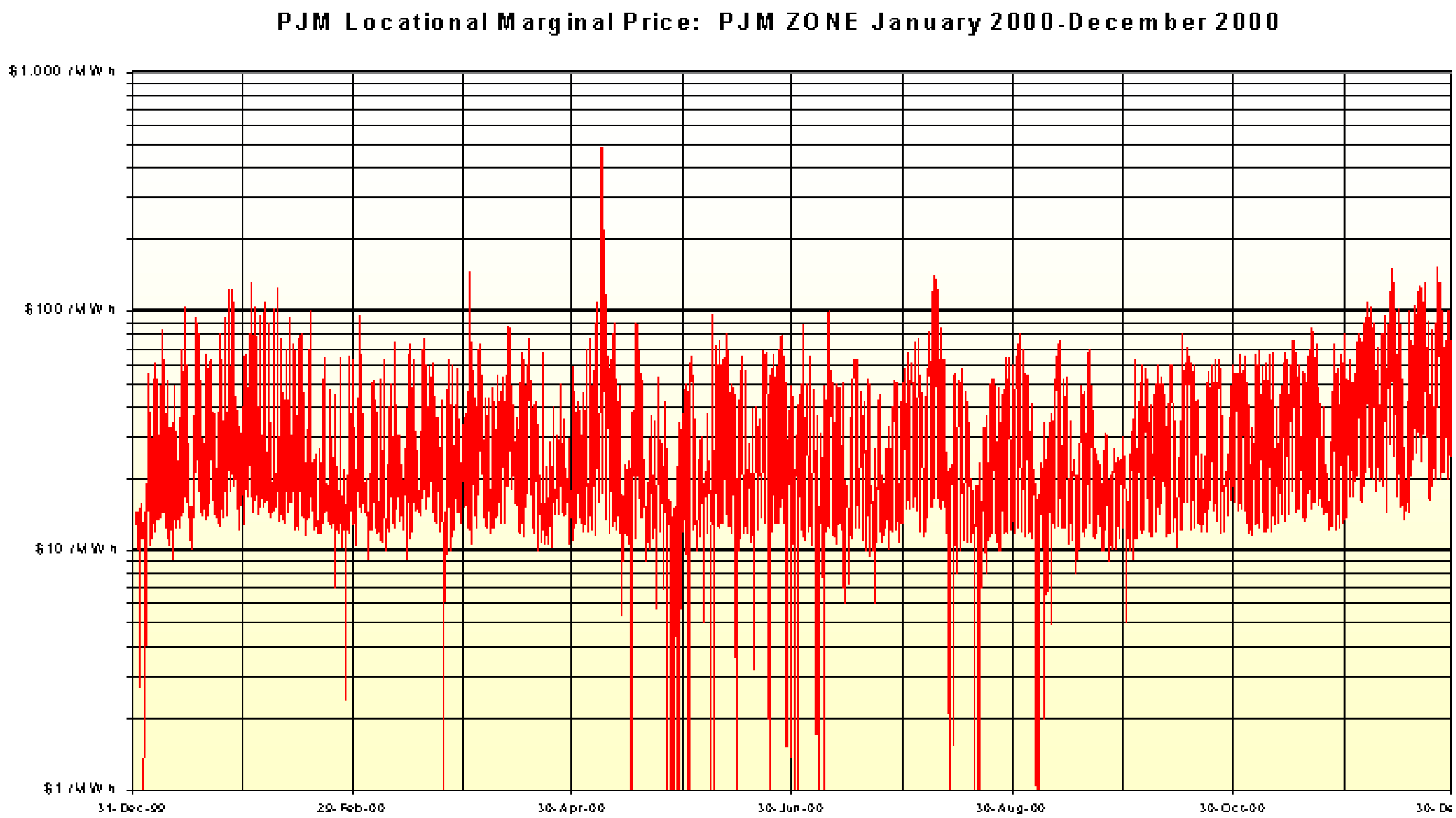


Exhibit 2-3 PJM Demand

PJM Day-Ahead Demand: PJM Zone January 1, 2000-December 31, 2000

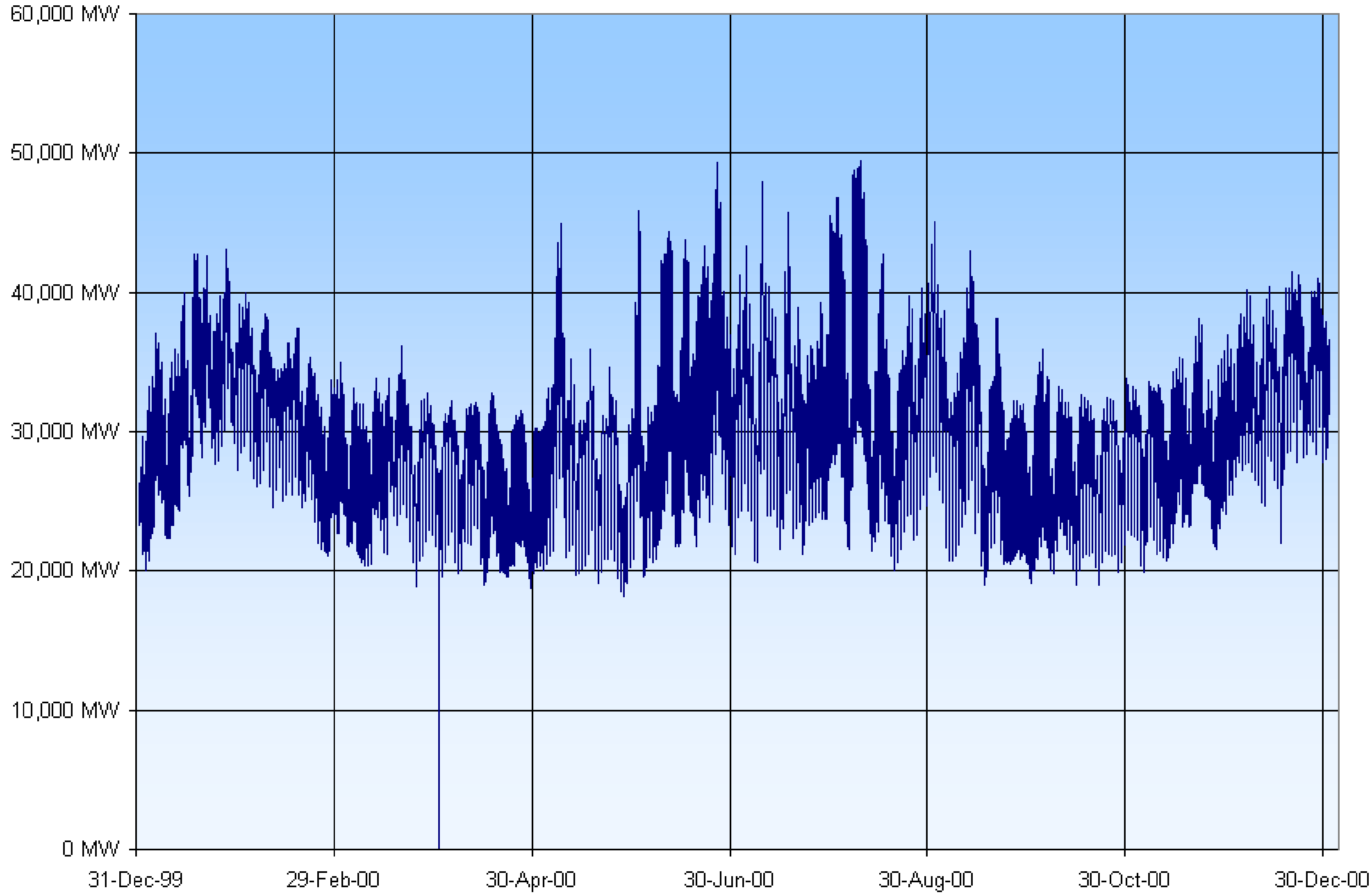


Exhibit 2-4 PJM Price Duration Histogram January 2000-December 2000

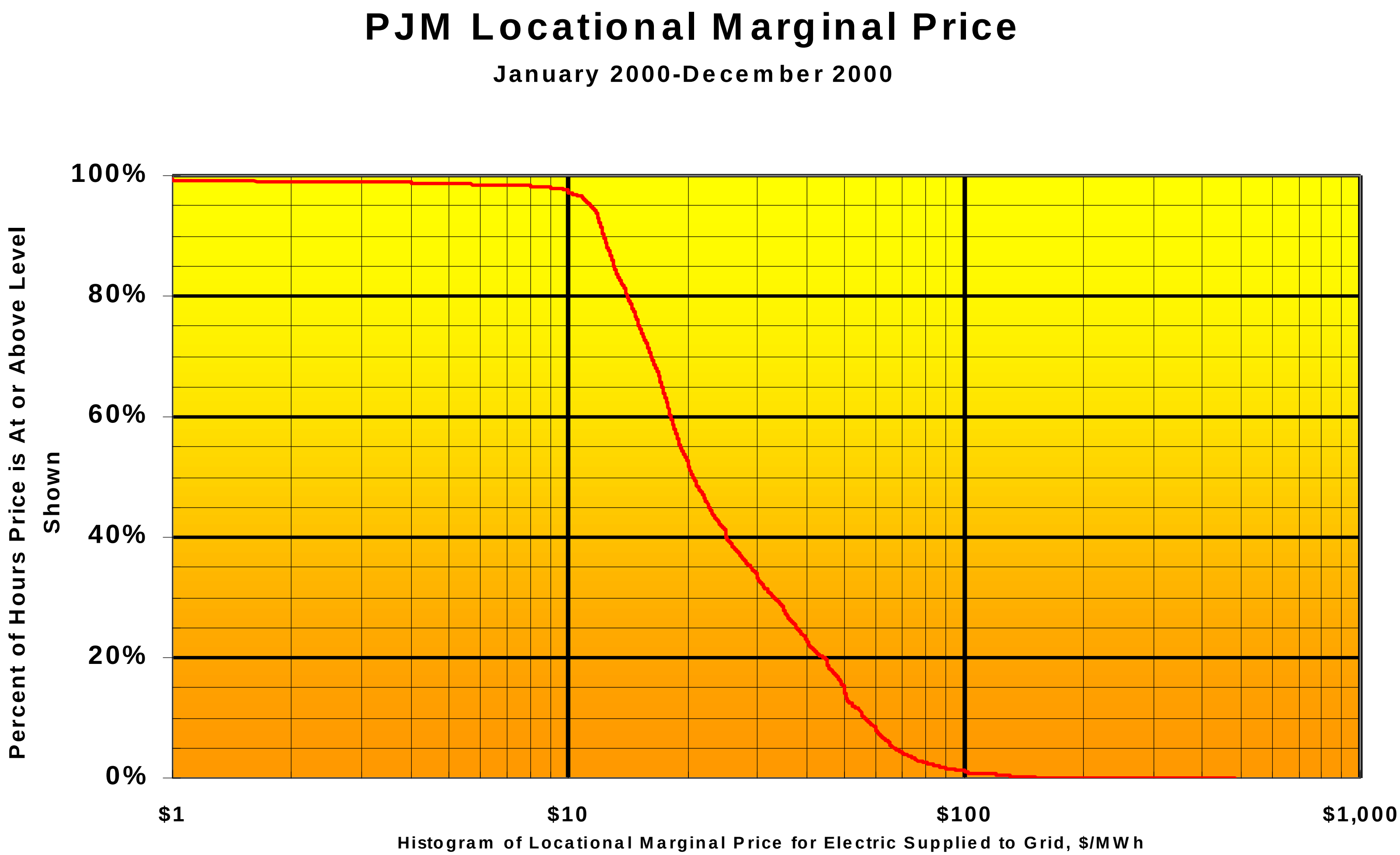
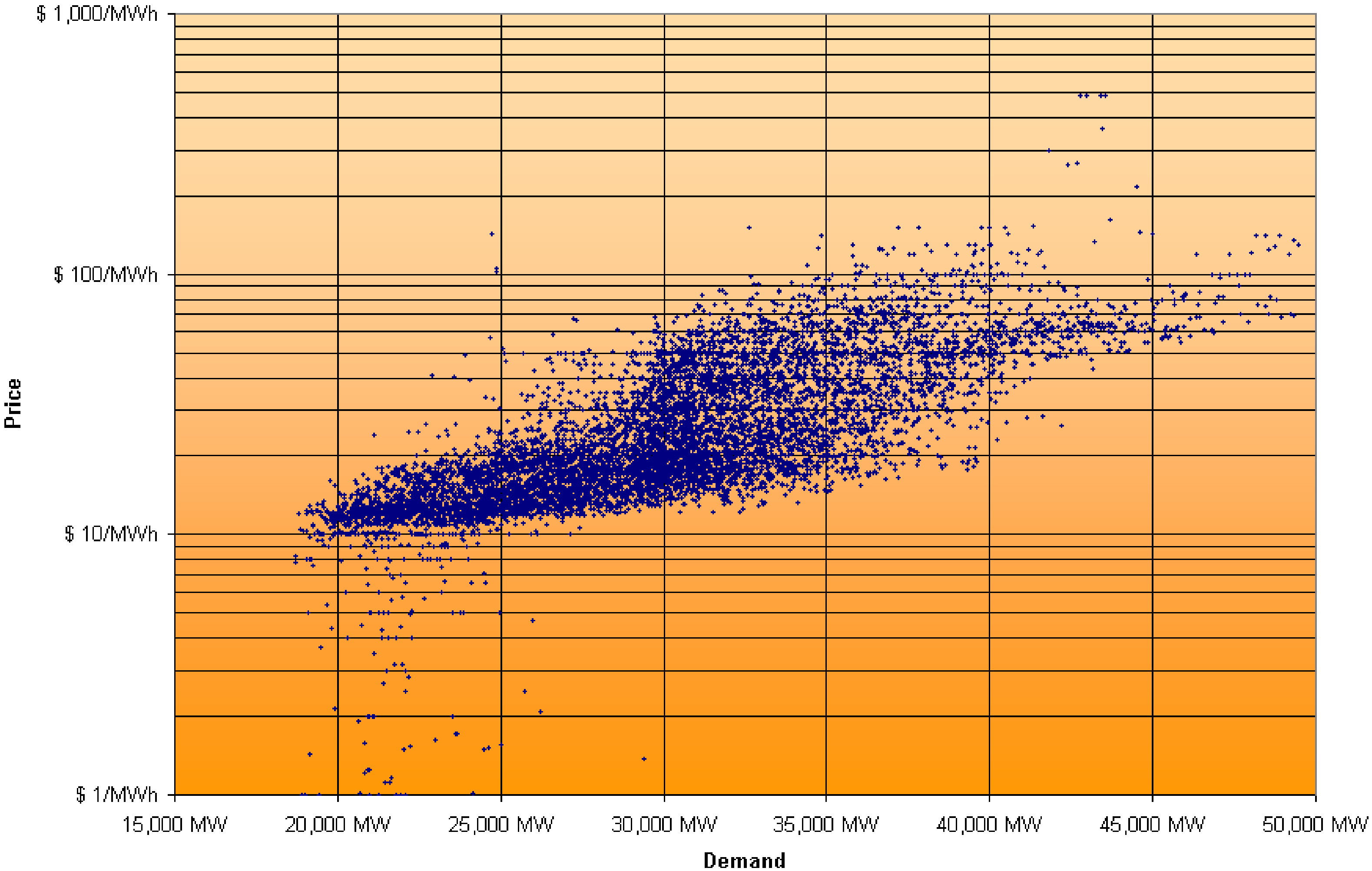


Exhibit 2-5
PJM Price vs. Demand Profile for Year 2000



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3. PJM Fuel Price and Financial Data Projections

GEMSET uses EIA projections and a range of other fuel price sources, in a mix that adjusts estimates to GEMSET's presumption of regional market conditions for its fleet production cost estimates. This section discusses the fuel prices that existed in the baseline year, and describes the range expectations for PJM fuel price scenarios used here.[§]

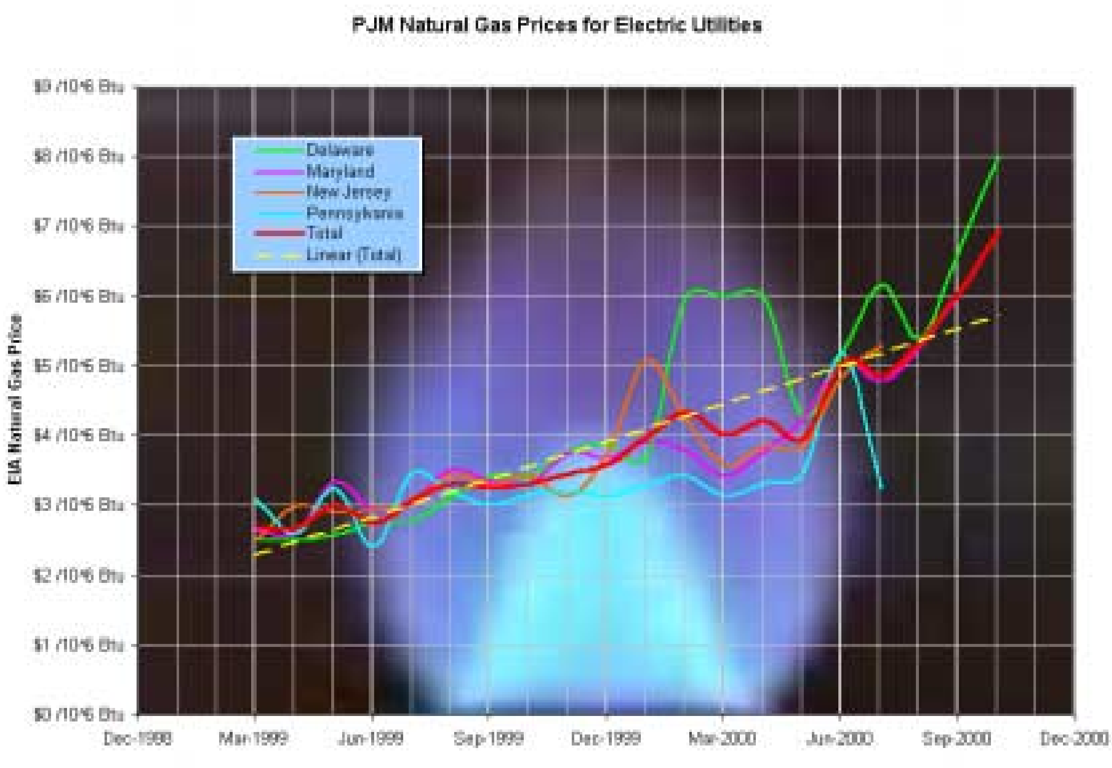
The day-ahead market price for electricity that occurred in year 2000 is the baseline used to project how the day-ahead price might vary under different load projections and different fuel price scenarios.

3.1 Historical Natural Gas Price in PJM for Year 2000

The baseline historical natural gas price data used for characterizing the PJM region is from the EIA's Natural Gas Monthly.[3] These data are shown in Exhibit 3-1.

[§] Department of Energy forecasts of fuel price are prepared by the Energy Information Agency (EIA) and are an authoritative reference for this type of information.[6] A new document (which wasn't available when this study was prepared) recently became available to readers needing information to be used for future GEMSET regional production cost modeling. This is the GEMSET Fuels Characterization document[1], which details the GEMSET expectation of regional prices of coal, lignite, #2 oil, #6 oil, and natural gas in all regions of the United States through year 2020. That GEMSET information is at a depth of detail suited to stacking units in the generation fleet in approximate production cost order.

Exhibit 3-1 Natural Gas Price in the PJM States



Using the linear regression of the average line, and extrapolating till the end of year 2000, the average natural gas price for the region for the baseline period of January 1, 2000 through December 31, 2000 is $ 5.01 / 10^6 Btu. For this study, we rounded, and thus assume:

Year 2000 Average PJM Natural Gas Price = $ 5.00 / 10^6 Btu

3.2 Historical Coal Price in PJM in Year 2000

The Historical coal price in the PJM Region has been exceptionally stable over the last few years, averaging between $1.25-1.35 / 10^6 Btu. This price is expected to continue for the short-term horizon, but rising slightly in the long-term.

3.3 Range of Fuel Price Assumed for Scenarios

Six natural gas price scenarios were cast, and two coal price scenarios were cast. These are shown in Exhibit 3-2.

Rationale for Natural Gas Price Range. Discussions were held with natural gas suppliers in the PJM region, and their estimation of future prices in the short-run are nothing less than spectacular. During certain periods last winter, prices actually were above $\$10/10^6$ Btu on the spot market. Electric suppliers were not contracting for long-term (2-3 years) futures in the natural gas market. Indications are that during the past summer when natural gas distribution companies would normally be buying gas for storage, the price was too high as a result of the electric generators buying gas for summer generation.

The futures market on the NYMEX have gas priced over $\$5.00 /10^6$ Btu, but not many are buying that far out at this time. Overall, it is expected that natural gas prices will remain at high levels throughout the 2001 time frame and probably settle at the $\$5\text{-}6 /10^6$ Btu price range over the next several years.

Rationale for Coal Price Range. Based on information provided by EIA on the quantity and price of contract coal in the Mid-Atlantic region, the price of coal has not increased over the last several years. In fact there has been a slight drop in price over that time frame. Current price is approximately $\$1.35 /10^6$ Btu. Therefore, a price of coal at $\$1.35 /10^6$ Btu's was selected for this analysis. That price was then held steady for the duration of the analysis for the year 2000. For sensitivity purposes, a price at $\$2.00 /10^6$ Btu was selected as a high price scenario in subsequent analyses.

Exhibit 3-2
Range of Fuel Price In Scenarios

Natural Gas Price Scenarios	Coal Price Scenarios
$\$ 3.00 / 10^6$ Btu	
$\$ 4.00 / 10^6$ Btu	
$\$ 5.00 / 10^6$ Btu (baseline)	**$\$ 1.35 / 10^6$ Btu (baseline)**
$\$ 6.00 / 10^6$ Btu	$\$ 2.00 / 10^6$ Btu
$\$ 8.00 / 10^6$ Btu	
$\$10.00 / 10^6$ Btu	

3.4 Other Fuels

There are other units in the PJM system that use different fuels. Since price scenarios were not cast for these units, these fuel prices were assumed fixed for all scenarios.

Exhibit 3-3
Fuel Price Held Fixed In All Scenarios

Fuel	Fuel Price
Bituminous glob	\$ 0.25 / 10^6 Btu
Coal	\$ 1.35 / 10^6 Btu baseline price *Scenario variable, see Exhibit 3-2*
Culm	\$ 0.25 / 10^6 Btu
Petroleum Fuels	\$ 4.52 / 10^6 Btu
Landfill Gas	\$ 0.00 / 10^6 Btu
Municipal Solid Waste	\$ 0.00 / 10^6 Btu
Natural Gas	\$ 5.00 / 10^6 Btu baseline price *Scenario variable, see Exhibit 3-2*
Petroleum Coke	\$ 1.00 / 10^6 Btu
Prepared Nuclear Fuel	\$ 0.99 / 10^6 Btu
Wood and Wood Waste	\$ 0.75 / 10^6 Btu
Water for Hydroelectric	\$ 0.00 / 10^6 Btu
Waste Process Gas	\$ 1.00 / 10^6 Btu

Parsons Corporation estimated all prices except petroleum fuels

Of these, petroleum fuels and uranium for nuclear reactors are significant sources of energy in PJM. The petroleum prices are averages taken from EIA data[4].

The price for nuclear fuel was estimated by Parsons based on overall February 2001 production cost data for the 2nd Quartile nuclear units in the United States, as reported by the Nuclear Energy Institute.[5] The U.S. fleet average nuclear unit heat rate was calculated from the EIA Annual Energy Outlook 2001[6] nuclear kWh generated (and Btu input to nuclear units), while Parsons assumptions of variable operating costs for nuclear units were used.

3.5 Financial Considerations

As with any assessment of new generating facilities, the actual cost of production and the carrying charges associated with the capital expenditures for such units must be considered. In the following sections, those implications are discussed to provide the background for the actual comparison of the differing types of generation.

3.5.1 Fuel Cost Calculations

For generating units, the fuel cost associated with that unit is the largest single cost component of the cost of electricity (COE). The total cost of fuel is a function of the fuel price, discussed above, and the heat rate associated with that unit. The heat rate is an indication of the efficiency of that unit. The lower the heat rate, the more efficient the unit.

For this analysis, a data base of every unit on the PJM system has been identified and the heat rate of that unit obtained from a variety of sources. To obtain the fuel cost of a unit, the capacity factor of the unit is also required. Capacity factor is defined as:

$$Cf = \frac{kWh}{nameplate\ rating \bullet period\ hours}$$

This capacity factor is a function of the load and hours the unit actually operated over a period of time. As an example, either of the two situations below would have the same capacity factor of 50% for the year:

- If units operated at its nameplate rating for half the hours in a year and were idle the remainder of the year.

- If a unit operated at 50% of its rated load for every hour of the year.

The accumulated hours of operation times the unit's load for each hour indicate the actual output of the unit in kWh. To obtain the amount of fuel used by that unit, the output times the average heat rate provides the amount of fuel used in Btu's over the time frame. Since fuel is priced as a function of Btu's (generally $/$10^6$ Btu), the total fuel cost can then be calculated.

In this analysis, estimates are made of the capacity factors of a unit, and then the heat rate is applied to obtain the total fuel cost when the nameplate rating of the unit is utilized. This total cost is then divided by the output to obtain a cost/kWh for that unit. For calculation simplicity, part load assessment of each unit is avoided. We use an average heat rate for the unit for the year to average the part load heat rate. In this fashion, nameplate output is used, and capacity factor is assumed to represent the fraction of the year the unit runs.

In subsequent sections, various graphs and tables will be presented for the three primary units under investigation. These include simple cycle gas turbines, combined cycle units run on gas, and a standard pulverized coal unit. In each case, the functions that are analyzed are heat rate, size, and capacity factor.

3.5.2 Operating & Maintenance Costs

Another cost component that must be identified for this analysis is the variable cost of operating the unit and maintaining the unit so that it functions when actually dispatched by the Independent System Operator (ISO). Since each unit has its own particular set of operating costs, it was decided to utilize reasonable industry averages for the differing types of units. Therefore, the selected cost components for the scenario variable units was chosen as follows: for a simple cycle unit it was set at $3/MWh for consumables and $11.20/kW for fixed O & M; the combined cycle unit at $4/MWh and $16.00/kW; and the coal unit at $7/MWh and $26.80/kW for fixed costs. Exhibit 3-4 shows the levels presumed for characterizing the threshold bid prices of the units in the fleet

As mentioned, each unit will have its own set of circumstances that come into the calculation. However, the use of a standard cost by type of unit is within normal actual cost parameters for generating stations, and is considered acceptable for this type of analysis.

Exhibit 3-4
Fixed O&M and Consumable Assumptions Used to Characterize Threshold bid prices for the PJM Fleet

Type of Unit	Fixed O&M
Coal and Solid Fuels *for coal, wood, culm, etc.*	***$ 26.80 / kW***
Simple Cycle Gas Turbine *for gas and petroleum fuels*	***$ 11.20 / kW***
Gas Turbine Combined Cycle *for gas and petroleum fuels*	***$ 16.00 / kW***

for all types of units:

Fuel Type of Unit	Consumables
Bituminous glob	$ 2.50 / MWh
Coal	$ 1.70 / MWh
Culm	$ 2.50 / MWh
Petroleum Fuels	$ 0.40 / MWh
Landfill Gas	$ 0.30 / MWh
Municipal Solid Waste	$ 2.50 / MWh
Natural Gas	$ 4.00 / MWh
Petroleum Coke	$ 2.50 / MWh
Nuclear	$ 2.77 / MWh †
Wood and Wood Waste	$ 2.50 / MWh
Hydroelectric	$ 3.26 / MWh
Waste Process Gas	$ 2.50 / MWh

† nuclear fuel O&M related to fuel handling and processing included with fuel price

3.5.3 Fixed Charge Rate Implications

Inasmuch as the competitive market in PJM is in its fourth year of operation, all of the plants that are currently planned for the region must follow certain guidelines before being accepted by the ISO. A queue system has been set up by the ISO in which those entities wishing to build a plant in PJM must complete a series of tasks, including permitting, before construction can actually begin. Once in the queue and if all guidelines are completed, then the plant can start construction regardless of its cost or type. Based on the information provided, it appears that fuel type is not a consideration in which type of plant is being built in the region. It is apparent that natural gas generation has been the choice of most of the entities in the queue prior to 2001 since gas prices have been relatively stable until recent times.

As described in Section 5, a capital cost versus size curve was established based on data provided by Gas Turbine World magazine. From those curves for simple cycle and combined cycle units, various sized units could be evaluated in this analysis as to their competitive position in the PJM region. Likewise, information was obtained on current coal projects under evaluation and their estimated capital cost per kW.

In order to determine a cost of electricity for each type of plant, and also recognizing the threshold bid price associated with each plant type, a fixed charge rate was calculated for each plant type based on certain financial parameters. The primary financial aspects related to each plant type are the capitalization ratio of debt versus equity, and the interest rate currently associated with electric generation projects by the financial community.

The calculated fixed charge rate includes taxes, insurance, allowance for funds used during construction, the interest rate, and the capitalization ratio of debt and equity. A cost of equity was assumed at three different levels for the evaluation: (1) a breakeven cost of 0% return; (2) a 15% rate of return; and (3) a 25% rate of return. In the case of gas-fueled generation, a capitalization ratio of 15% equity and 85% debt was assumed. This is based on recent financing of private power projects in the northeast. For coal, a more conservative estimate of 25% equity and 75% debt was assumed to account for the additional risk associated with new coal facilities. In Exhibit 3-5 below, the actual Fixed Charge Rates applied to each technology are summarized:

Exhibit 3-5
Fixed Charge Rate Applied

Rate of Return on Equity	*Simple Cycle*	*Combined Cycle*	*Coal*
0%	0.1115	0.1115	0.1029
15%	0.1419	0.1419	0.1534
25%	0.1637	0.1637	0.1913

3.5.4 Cost of Electricity

The calculated cost of electricity for each of the technologies is a function of three cost components described above. These include the cost of fuel, calculated by taking the assumed capacity factor (number of hours operating) times the unit size and heat rate times a cost of fuel; the fixed and consumable cost of operation and maintenance; and the annual fixed charge rate to recover the cost of capital. For existing units on PJM, the actual cost of capital is generally ignored when a bid is placed on the day-ahead market, and therefore, dispatch is determined almost solely on a bid price assessment.

This cost of electricity has been calculated for each of the three types of units under consideration by size and heat rate, a variable cost of production, and an assumed rate of return at a breakeven point to repay the capital portion associated with the differing unit sizes.

In Exhibit 3-6 below, the simple cycle gas turbine unit has been used as an example of the calculations made to determine the estimated COE. The estimated total cost, consisting of fuel cost, fixed and consumable O & M, and the capital component are added together to give a total cost per annum. That total cost is then divided by the amount of production under an assumed capacity factor to give the per unit COE, which will be shown later in Exhibit 3-9. All of these calculations are made under the baseline assumptions of PJM year 2000 conditions. The calculations differ for each scenario discussed later in the Section 4, "Modeling the PJM Generation Fleet Under Different Fuel Scenarios."

Exhibit 3-6
Simple Cycle Gas Turbine Estimates

MW	SSGT: Plant Cost	SSGT: Heat Rate	Fuel (000's)	Fixed O & M (000's)	Consumables (000's)	Capital (000's)	Total (000's)
50 MW	$327 /kW	10,611 Btu/kWh	$2,791	$560	$16	$1,883	$5,249
100 MW	$281 /kW	10,053 Btu/kWh	$6,165	$1,120	$37	$3,230	$10,552
150 MW	$257 /kW	9,740 Btu/kWh	$10,241	$1,680	$63	$4,429	$16,414
200 MW	$241 /kW	9,524 Btu/kWh	$14,188	$2,240	$89	$5,542	$22,059
250 MW	$229 /kW	9,359 Btu/kWh	$18,456	$2,800	$118	$6,593	$27,967

The same type of analysis was conducted for a combined cycle unit and a coal unit. As mentioned, the COE will vary depending on the heat rate and capacity factor. The capital component does not vary by those factors, but rather by the size and capital cost of the unit, and its calculated fixed charge rate. Simple cycle and combined cycle units were assumed to have the same carrying charge for capital since the capitalization ratio was assumed to be the same.

The same table as presented above for the simple cycle gas turbine is presented below in Exhibit 3-7 for the combined cycle and in Exhibit 3-8 for the coal units.

Exhibit 3-7
Gas Turbine Combined Cycle Estimates

MW	GTCC: Plant Cost	GTCC: Heat Rate	Fuel (000's)	Fixed O & M (000's)	Consumables (000's)	Capital (000's)	Total (000's)
100 MW	$641/kW	7,554 Btu/kWh	$8,275	$1,600	$88	$7,373	$17,336
200 MW	$559/kW	7,210 Btu/kWh	$17,053	$3,200	$189	$12,847	$33,289
300 MW	$515/kW	7,016 Btu/kWh	$25,815	$4,800	$294	$17,777	$48,685
400 MW	$487/kW	6,881 Btu/kWh	$34,967	$6,400	$407	$22,383	$64,157
500 MW	$465/kW	6,779 Btu/kWh	$43,057	$8,000	$508	$26,764	$78,329

Note: Why are MW in Blue?

Exhibit 3-8
Pulverized Coal Estimates

MW	PC Coal: Plant Cost	PC Coal: Heat Rate	Fuel (000's)	Fixed O & M (000's)	Consumables (000's)	Capital (000's)	Total (000's)
400 MW	$1,100 /kW	9,934 Btu/kWh	$35,241	$10,720	$4,467	$45,276	$95,704
500 MW	$1,045 /kW	9,692 Btu/kWh	$44,131	$13,400	$5,734	$53,765	$117,031
600 MW	$993 /kW	9,456 Btu/kWh	$53,003	$16,080	$7,059	$61,292	$137,434
700 MW	$943 /kW	9,225 Btu/kWh	$61,093	$18,760	$8,340	$67,932	$156,125
800 MW	$896 /kW	9,000 Btu/kWh	$69,824	$21,440	$9,770	$73,755	$174,788

3.5.5 Presumed Dispatch

Having calculated a COE for each of the differing units, it is now necessary to compare that cost of electricity to the price currently in affect in the PJM region. Based on an hour by hour accumulation of day-ahead prices in PJM for the year ending December 31, 2000, an S-Curve was histogram developed from the lowest to the highest price experienced in PJM. This S-Curve is a cumulative distribution function, and is shown graphically in Section 2, as Exhibit 2-4 on page 2-8. This histogram is the basis for the assumed dispatching levels of the new units under current market conditions. It must be kept in mind that the curve reflects a modest gas price in the early months of the year, and the rather rapid increase in prices resulting from high gas prices in the latter months of the year 2000.

Since most units are dispatched on the basis of threshold bid price only, it was decided to calculate the threshold bid price of the new units based on the current cost of fuel and variable O&M. The capital component of any power plant has not been considered in the threshold bid price since a portion of that cost is recovered by a capacity component that is separate from the posted energy price. That calculated cost was then compared against the S-Curve to see how many hours the unit would have been dispatched if it was already on the PJM system and could actually bid a price equivalent to its own threshold bid price.

By reading the price on the curve at the level of threshold bid prices for that unit, the number of hours that the unit is likely to be dispatched is calculated. This then gives the estimated dispatch levels and the capacity factor of the unit. With that S-Curve is a corresponding calculation of the estimated revenue associated with that number of hours of operation, which can then be compared against the calculated COE to see if the unit can make a positive rate of return for the owner. In the Tables shown below are calculations of the revenue expected from the assumed capacity factor of the unit. That revenue amount is divided by the amount of production from that capacity factor and is compared against the COE for each unit at the differing sizes and heat rate efficiencies. If the revenue calculation is higher than the COE, then the return is expected to be positive. The specific graph for the Simple Cycle unit is shown later in Section 9.1 "Prospects for SSGT, GTCC, and Coal Projects Under Baseline Scenario 1" as Exhibit 9-1; this exhibit is found on page 9-63.

Also included on the graph is the expected PJM revenue based on the price levels for the year 2000. For the simple cycle options at varying size levels and at the current price of $5.00 per million Btu’s, no breakeven level is achieved under last years day-ahead prices. In Exhibit 3-9 below, the Threshold bid price, the expected capacity factor and the COE versus the revenues are presented for the Simple Cycle.

Exhibit 3-9
Simple Cycle Gas Turbine COE vs. PJM Revenue

MW	SSGT: Threshold Bid Price	SSGT: Actual Capacity Factor Possible =f(prod cost)	Output	SSGT: Break-Even COE Needed	SSGT: Actual Revenue =f(prod cost, actual Cf)
50 MW	$53.36/MWh	0.120 Cf	52,600 MWh	$ 99.79 /MWh	$ 73.60 /MWh
100 MW	$50.56/MWh	0.140 Cf	122,650 MWh	$ 86.03 /MWh	$ 70.38 /MWh
150 MW	$49.00/MWh	0.160 Cf	210,300 MWh	$ 78.05 /MWh	$ 67.79 /MWh
200 MW	$47.92/MWh	0.170 Cf	297,950 MWh	$ 74.04 /MWh	$ 66.63 /MWh
250 MW	$47.10/MWh	0.180 Cf	394,375 MWh	$ 70.92 /MWh	$ 65.53 /MWh

As indicated the COE is higher at all sizes when compared against the expected revenues.

Likewise, for the same analysis, no breakeven point is achieved for combined cycle units of varying sizes and heat rates. That analysis is shown graphically later in Section 9.1, "Prospects for SSGT, GTCC, and Coal Projects Under Baseline Scenario 1."

Exhibit 3-10 below provides the same information for the Combined Cycle units as presented for the Simple cycle. As with the Simple Cycle, the COE is higher than the revenue expected if the prices are the same as those bid in 2000.

Exhibit 3-10
Gas Turbine Combined Cycle COE vs. PJM Revenue

MW	GTCC: Threshold Bid Price	GTCC: Actual Capacity Factor Possible =f(prod cost)	Output	GTCC: Break-Even COE Needed	GTCC: Actual Revenue =f(prod cost, actual Cf)
100 MW	$38.17/MWh	0.250 Cf	219,075 MWh	$ 79.13 /MWh	$ 58.89 /MWh
200 MW	$36.45/MWh	0.270 Cf	473,050 MWh	$ 70.37 /MWh	$ 57.26 /MWh
300 MW	$35.48/MWh	0.280 Cf	735,900 MWh	$ 66.16 /MWh	$ 56.48 /MWh
400 MW	$34.81/MWh	0.290 Cf	1,016,300 MWh	$ 63.13 /MWh	$ 55.73 /MWh
500 MW	$34.29/MWh	0.290 Cf	1,270,375 MWh	$ 61.66 /MWh	$ 55.73 /MWh

For a coal unit of 600-800 MW size, there are capacity factors and COE levels that would actually provide a positive return on investment under the existing prices experienced in PJM for the year 2000. That is shown graphically in Section 6.1.3, and in Exhibit 3-11 below.

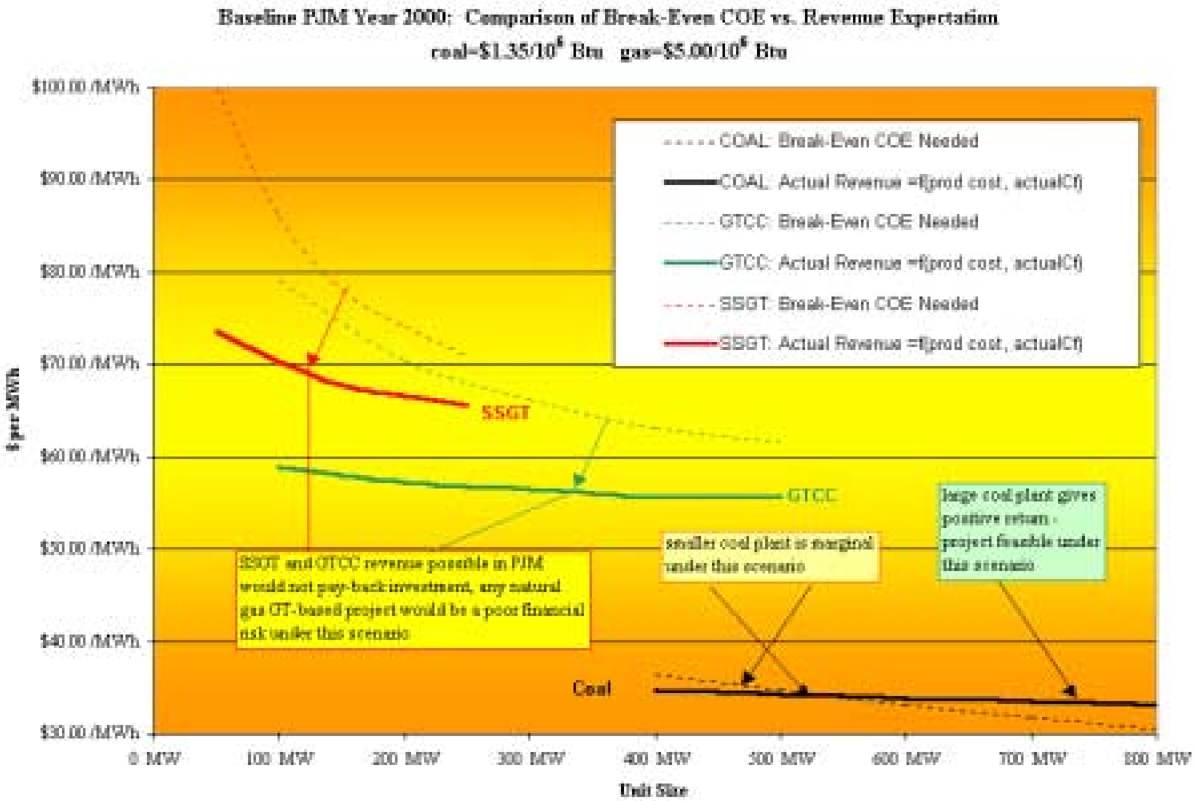
Exhibit 3-11
Pulverized Coal COE vs. PJM Revenue

MW	COAL: Threshold Bid Price	COAL: Actual Capacity Factor Possible =f(prod cost)	Output	COAL: Break-Even COE Needed	COAL: Actual Revenue =f(prod cost, actual Cf)
400 MW	$15.11/MWh	0.750 Cf	2,627,701 MWh	$ 36.42 /MWh	$ 34.80 /MWh
500 MW	$14.78/MWh	0.770 Cf	3,372,874 MWh	$ 34.70 /MWh	$ 34.28 /MWh
600 MW	$14.47/MWh	0.790 Cf	4,152,150 MWh	$ 33.10 /MWh	$ 33.79 /MWh
700 MW	$14.15/MWh	0.800 Cf	4,905,600 MWh	$ 31.83 /MWh	$ 33.54 /MWh
800 MW	$13.85/MWh	0.820 Cf	5,746,799 MWh	$ 30.41 /MWh	$ 33.06 /MWh

This leads to the conclusion that PJM pricing is under-valued in regards to supporting the addition of new units to their system at today's fuel pricing.

Exhibit 3-12 is a summary of the economic performance of the three types of generating units and their expected revenues when compared against the break even revenue amount from PJM's pricing levels for the year 2000. This baseline case forms the "Baseline Scenario 1," case in the studies, that is, PJM as it actually operated in Year 2000. For convenience, this curve is repeated later in the reporting of the results of the various scenarios evaluated in this study

Exhibit 3-12
SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2000 PJM Day-Ahead Electric Price



In this summary of the three types of generation under investigation using today's fuel prices, it can be shown that only the coal unit currently achieves some level of return at the larger sizes. If, however, an owner had secured a long term contract natural gas price at the gas price in the beginning of 2000, then each unit size for the natural gas type units would actually make a positive rate of return. This assessment is presented as Scenario 5 in Section 6.5

4. Modeling the PJM Generation Fleet Under Different Fuel Scenarios

This section discusses how these market assessments were accomplished.

4.1 Presumptions

The market projections assume:

- PJM bi-lateral contract price will trend toward the day-ahead free-market price.
- Market price is only loosely linked to threshold bid price; there is a large "random-walk" on any given hour, however, it is presumed that there is a tendency that price is linked to demand in some fashion.
- If a competitor has a lower marginal threshold bid price than another, he can always underbid that other competitor and win, whenever demand is less than the owner's particular marginal price dispatch order.
- On average, the market price will deviate about the price / demand / supply. While an individual hour can not be accurately predicted, it is presumed here that on average, the deviations about a predicted level will have similar variability to those of the actual market in the prior year. That is, a scenario's variations about price versus threshold bid price will on average be similar to the variations that actually occurred in the prior year.
- The study presumes that differences in electric price under these several fuel price scenarios are not large enough to substantially alter demand in the region.

4.2 Fleet Dispatch Stacking Order Assumed

For any given scenario, all of the units on PJM are assumed to compete successfully in their stacking order on the basis of their threshold bid prices. That is, the unit with the lowest threshold bid price in the fleet will capture the first increment in demand and thus have the highest capacity factor. The next unit in threshold bid price-stacking order will take the next increment in demand, etc. In periods of low demand, only the lowest price units would be used; in periods of peak demand, most all units would be used.

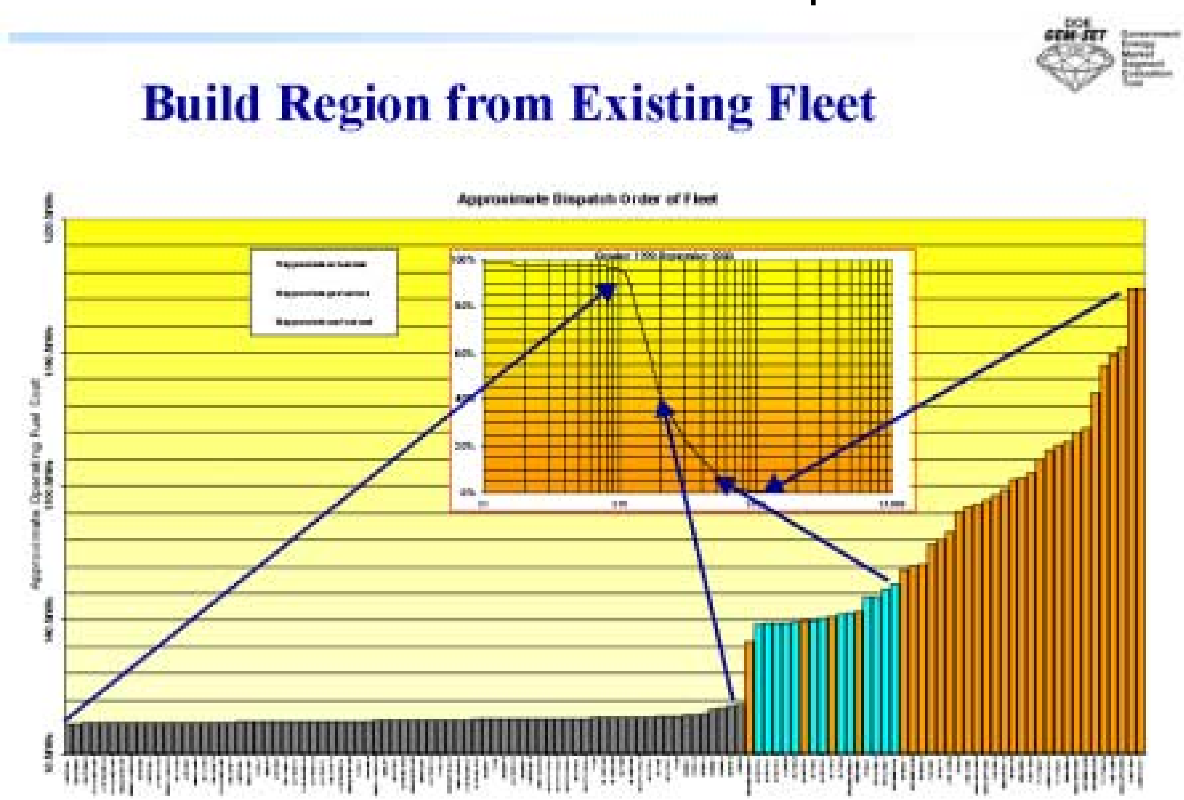
This stacking order changes depending on the scenario. For example, if natural gas price were lower in one scenario versus another, then the natural gas units would be dispatched earlier in the stacking order.

4.3 Relating Threshold Bid Price to Demand

Threshold bid price forms the basis for stacking the competitive order of dispatch for all units on the PJM system.

Stacking the Existing Fleet. Exhibit 4-1 is a sketch (not real data) that shows the price histogram as the small inset curve, and gives a visual indication of how the units in the fleet meet that price demand.

Exhibit 4-1
Sketch Illustrating the Stacking of the Existing Fleet to Establish Threshold Bid Price vs. Demand Relationship



This sketch gives a visual impression of the process; however, the actual mapping of the units in the fleet to price is a more sophisticated operation than this visualization suggests. In the GEMSET model, it is assumed that perfect competition occurs, so that the lowest price producer is assumed clever enough to always underbid the next higher threshold bid price producer. While this assumption is a simplification, on average, it is a reasonable enough presumption to characterize the threshold bid price characteristics of the region. With the large number of generating units within the region, this provides a good approximation of the order in which units will make up the generation.

Under this presumption, at low demand periods, when the price is low, only the lowest threshold bid price units can afford to operate. As demand increases, the next higher threshold bid price unit is added, then the next, until at the periods of peak demand, finally, the high threshold bid price peaking units gain a high enough return to be called into service.

In the GEMSET model, the stacking is used to establish the generating cost characteristics of the fleet for each level of demand. This stacking is discussed in detail later on in Section 6, "PJM Unit Data." The baseline threshold bid price versus cumulative megawatt capability of all of the PJM units are plotted as Exhibit 7-1 on page 7-56. The plot compares this baseline to the re-stacked prices with each fuel price scenario, resulting in the estimated threshold bid price versus demand curve shown in the other curves of Exhibit 7-1 on page 7-56. Once this baseline stacking order versus system demand is known, the estimated threshold bid prices can be mapped against actual day-head system price. This mapping occurs hour by hour for each of 8760 hours in the year. Historical price and demand is known, so the presumed threshold bid price can be read from the dispatch stacking order developed under these rules.

This results in the estimated threshold bid price histograms for each scenario shown.

4.4 Handling the Randomness of Competitive Market Effects In Order to Forecast Alternate Scenarios

While threshold bid price is an important driver for bid price, in a competitive market there are many reasons why bid price varies. It is assumed that these 'gamesmanship' effects are random, and driven by competition; however, it is presumed that on average the competitive gamesmanship market variability of cost versus bid price that actually occurred in the prior year will likely be similar to that in any given scenario.

In GEMSET, an "inferred competition ratio" was established for each hour of the year, and presumed in the aggregate to reasonably approximate competitive variability in other years and scenarios. This ratio maps hour-by-hour the presumed threshold bid price for each hour's demand level and establishes the ratio between cost to the actual day-ahead price in that hour. That hour-by-hour baseline inferred competition ratio is then used to map all future scenarios. It is presumed that while any given hour is random, the aggregate trend of competitive pressures will over a year range through similar variations. That is, while an individual hour can not be predicted with any accuracy due to the random nature of competition, still, over 8760 hours, the amount of variability between price and demand are more likely to be similar on average.

4.5 Forecasting a Scenario's Day-Ahead Electric Price Profile

Re-Stacking the Dispatch Order. The first action needed to build the expectation of a scenario's day-ahead electric price profile is to re-stack the units considered. These must be re-stacked in the revised threshold bid price order. The threshold bid prices of units will change since fuel price or demand profile, or other factors might change in any scenario, compared to the circumstance that existed in the historical data baseline. In any given scenario individual units will likely have a different production order than in the baseline. For example, suppose gas price were presumed lower in an evaluation scenario, Exhibit 4-2. Here, several natural gas units have been "promoted" in their dispatch order to earlier dispatch, while oil units were "demoted" since their scenario threshold bid price places the lower-priced units ahead of what have now become more costly units. Exhibit 4-2 is a sketch to give a visual impression to illustrate the concept. The actual GEMSET re-stacking process is more sophisticated.

Exhibit 4-2
Re-stacking the Fleet to Establish Threshold Bid Prices vs. Demand Relationship for A Scenario

Re-Stacked Scenario Threshold Bid Price Histogram. Once the units are re-stacked, a scenario's threshold bid prices versus cumulative megawatt capability of all of the scenario units are plotted. This would have a similar appearance to the histogram plot shown later as Exhibit 7-1 on page 7-56.

Demand Growth Extrapolation. Since demand in a scenario may exceed the available capacity, it is important to make judgements on the likely price for imported replacement energy. In GEMSET a linear extrapolation is used for the presumed threshold bid price for all capacity beyond that of the fleet. The extrapolated scenario threshold bid price versus cumulative megawatt "tail" is added to the re-stacked histogram, to form the final threshold bid price versus demand curve.

Scenario Day-Ahead Price Estimate. Once this scenario threshold bid price versus demand curve is known, the scenario's hour-by-hour demand is used to read this curve and establish the scenarios hour-by-hour expected threshold bid price. These are then mapped hour-by-hour against the "inferred competition ratio" for each hour that was established from the baseline. Thus, hour-by-hour day-head system price can be inferred. This mapping occurs hour by hour for each of 8760 hours in the year. The scenario's electricity price is established. The day-ahead electric price is a function of the scenario's demand and the threshold bid prices for the units in the system under the scenarios production price constraints.

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5. PJM Market Study Assumptions

This section discusses the market assumptions used to model gas turbines in PJM, and to compare them to coal units.

5.1 Simple Cycle Turbogenerator Assumptions

Gas Turbine Peaker Price. The simple cycle turbogenerator price levels and the turnkey combined cycle plant budget price levels were taken from the 1999-2000 Gas Turbine World Handbook. The following cost bases were also taken from this source, although were written in a different format for clarity and quick-reference.

These costs represent budgetary average equipment-only price levels for a new basic gas turbine electric power generating package including:

- Single-fuel gas turbine
- Air-cooled electric generator (some larger units are H_2-cooled)
- Skid and Enclosure
- Inlet and Exhaust ducts and Exhaust silencer
- Standard control and starting systems
- Conventional combustion system (unless noted as dry low emissions)
- F.O.B at the factory in 1999 U.S. dollars

Prices can vary significantly depending on the scope of plant equipment, geographical area, special site requirements and competitive market conditions. These F.O.B. prices need to be adjusted for actual installation costs.

Exhibit 5-1
<u>Gas Turbine World</u> Simple Cycle Gas Turbogenerator Price Levels

Does NOT include adjustment to actual installed price

Simple Cycle Turbogenerator Price Levels

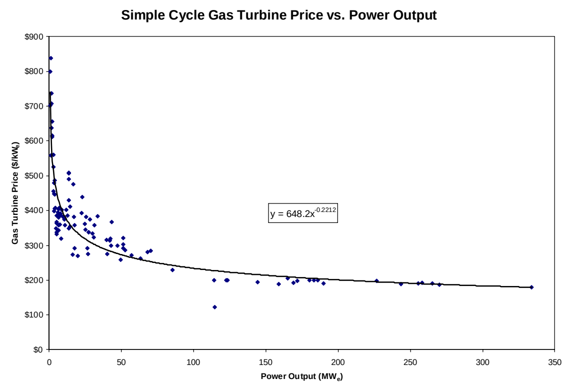
Manufacturer	Model	ISO Base Load (kW_e)	LHV Heat Rate (Btu/kW-hr)	LHV Efficiency	Budget Price	$ per kW_e
AlliedSignal	ASE8-1000	548	15,440	22.1	$385,000	$703
Pratt & Whitney Canada	ST6L-813	848	13,175	25.9	$677,500	$799
Turbomeca	Makila TI	1,050	12,580	27.1	$880,000	$838
Solar	Saturn 20	1,210	13,970	24.4	$675,000	$558
Dresser-Rand	KG2-3C	1,450	21,620	15.8	$1,070,000	$738
Kawasaki Heavy Industries	M1A13D	1,473	14,300	23.9	$940,000	$638
ABB Alstom	Hurricane	1,660	13,915	24.5	$1,175,000	$708
Dresser-Rand	KG2-3E	1,830	21,070	16.2	$1,200,000	$656
Pratt & Whitney Canada	ST18A (Dry)	1,960	11,280	30.2	$1,200,000	$612
Nuovo Pignone-Turbotecnica	PGT2	2,000	13,650	25.0	$1,230,000	$615
Orenda Aerospace	OGT2500	2,730	12,515	27.3	$1,435,000	$526
Mashproekt	UGT-2500	2,850	11,975	28.5	$1,300,000	$456
Kawasaki Heavy Industries	M1T13D	2,900	14,460	23.6	$1,625,000	$560
Pratt & Whitney Canada	ST30 (Dry)	3,340	10,660	32.0	$1,600,000	$479
Mashproekt	UGT-3200	3,400	11,010	31.0	$1,525,000	$449
Solar	Centaur 40	3,515	12,240	27.9	$1,400,000	$398
ABB Alstom	TB5000	3,925	13,250	25.8	$1,910,000	$487
Rolls-Royce	501-KB5S	3,950	11,765	29.0	$1,600,000	$405
Pratt & Whitney Canada	ST40 (Dry)	4,040	10,310	33.1	$1,800,000	$446
Solar	Mercury 50 DLE	4,180	8,750	39.0	$1,700,000	$407
Solar	Centaur 50	4,580	11,625	29.4	$1,600,000	$349
Solar	Taurus 60	5,200	11,260	30.3	$1,750,000	$337
Nuovo Pignone-Turbotecnica	PGT5	5,220	12,720	26.8	$1,900,000	$364
ABB Alstom	Typhoon 5.25	5,250	11,300	30.2	$2,020,000	$385
Rolls-Royce	501-KB7	5,275	11,200	30.5	$1,750,000	$332
GHH Borsig	THM1203R	5,320	10,900	31.3	$1,950,000	$367
Kawasaki Heavy Industries	M7A-01	5,840	11,230	30.4	$2,310,000	$396
Rolls-Royce	501-KH5 (SI)	6,420	8,560	39.9	$2,300,000	$358
Rolls-Royce	601-KB9	6,450	10,615	32.1	$2,450,000	$380
Mashproekt	UGT-6000	6,700	10,835	31.5	$2,300,000	$343
Orenda Aerospace	GT6001	6,700	10,840	31.5	$2,700,000	$403
ABB Alstom	Tornado	6,755	10,820	31.5	$2,750,000	$407
Kawasaki Heavy Industries	M7A-02	6,960	11,050	30.9	$2,700,000	$388
Solar	Taurus 70 DLE	7,250	10,400	32.8	$2,600,000	$359
ABB Alstom	Tempest	7,720	11,265	30.3	$2,995,000	$388
Rolls-Royce	601-KB11	7,920	10,350	33.0	$3,100,000	$391
Mashproekt	UGT-6000+	8,300	10,340	33.0	$2,650,000	$319
GHH Borsig	THM1304D	8,970	12,570	27.1	$3,600,000	$401
Solar	Mars 90	9,440	10,880	31.4	$3,600,000	$381
Solar	Mars 100	10,700	10,515	32.5	$4,000,000	$374
Mashproekt	UGT-10000	10,780	9,480	36.0	$3,850,000	$357
Nuovo Pignone-Turbotecnica	PGT10B	11,700	10,660	32.0	$4,700,000	$402
ABB Alstom	Cyclone DLE	12,900	10,070	33.9	$4,980,000	$386
Solar	Titan 130	13,500	10,250	33.3	$4,700,000	$348
Mitsui Engineering	SB60-1	13,570	11,490	29.7	$5,830,000	$430
?????	RLM1600	13,690	9,710	35.1	$6,930,000	$506
GE Ind. Aeroderivative GTs	LM1600PA	13,750	9,620	35.5	$7,000,000	$509
Nuovo Pignone-Turbotecnica	PGT16	13,750	9,670	35.3	$6,750,000	$491
Mitsubishi Heavy Industries	MF111B	14,570	11,020	31.0	$6,000,000	$412
Rolls-Royce	Avon	14,580	12,100	28.2	$5,175,000	$355
Mashproekt	UGT-16000	16,300	11,020	31.0	$4,450,000	$273
GE Ind. Aeroderivative GTs	LM1600-PB STIG	16,900	8,610	39.6	$8,030,000	$475
ABB Alstom	GT35	17,000	10,635	32.1	$6,500,000	$382
????	GT15000	17,500	9,750	35.0	$6,275,000	$359
Mashproekt	UGT-15000	17,500	9,750	35.0	$5,100,000	$291
Mashproekt	UGT-15000+	20,000	9,480	36.0	$5,400,000	$270
Nuovo Pignone-Turbotecnica	PGT25	22,450	9,395	36.3	$8,815,000	$393
GE Ind. Aeroderivative GTs	LM2500PE	22,800	9,275	36.8	$10,000,000	$439
ABB Alstom	GT10B	24,700	9,985	34.2	$8,925,000	$361
Rolls-Royce	RB211-6556	25,300	9,750	35.0	$8,750,000	$346
Turbo Power	FT8	25,470	8,950	38.1	$9,725,000	$382
GE Ind. Aeroderivative GTs	PG5371PA	26,300	11,990	28.5	$7,680,000	$292
Mashproekt	UGT-25000	26,700	9,350	36.5	$7,350,000	$275
????	GT25000	27,500	9,710	35.1	$9,270,000	$337
Rolls-Royce	RB211-6562	27,520	9,415	36.2	$9,275,000	$337
GE Ind. Aeroderivative GTs	LM2500PH (SI)	28,060	8,320	41.0	$10,500,000	$374
Mitsubishi Heavy Industries	MF-221	30,000	10,670	32.0	$10,000,000	$333
Rolls-Royce	RB211-6761	30,950	8,735	39.1	$10,000,000	$323
GE Ind. Aeroderivative GTs	LM2500+PK	31,320	8,640	39.5	$11,200,000	$358

Exhibit 5-2 is a scatter plot of data collected for Simple Cycle gas turbines as described above. The trendline is a regression analysis fit of the data. An exponential fit approximates the direction of the data. These data however, are for FOB prices. Parsons has installed many such systems, and used this experience base to adjust the level of the curve to actual expected turnkey installed prices.

Exhibit 5-3 is a scatter plot of Gas Turbine World FOB prices for simple cycle gas turbines adjusted by Parsons to match actual installation cost levels. The trendline is a power curve fit of the data. This may not be the best option to fit the data, but it seemed to closely resemble the direction of the data.

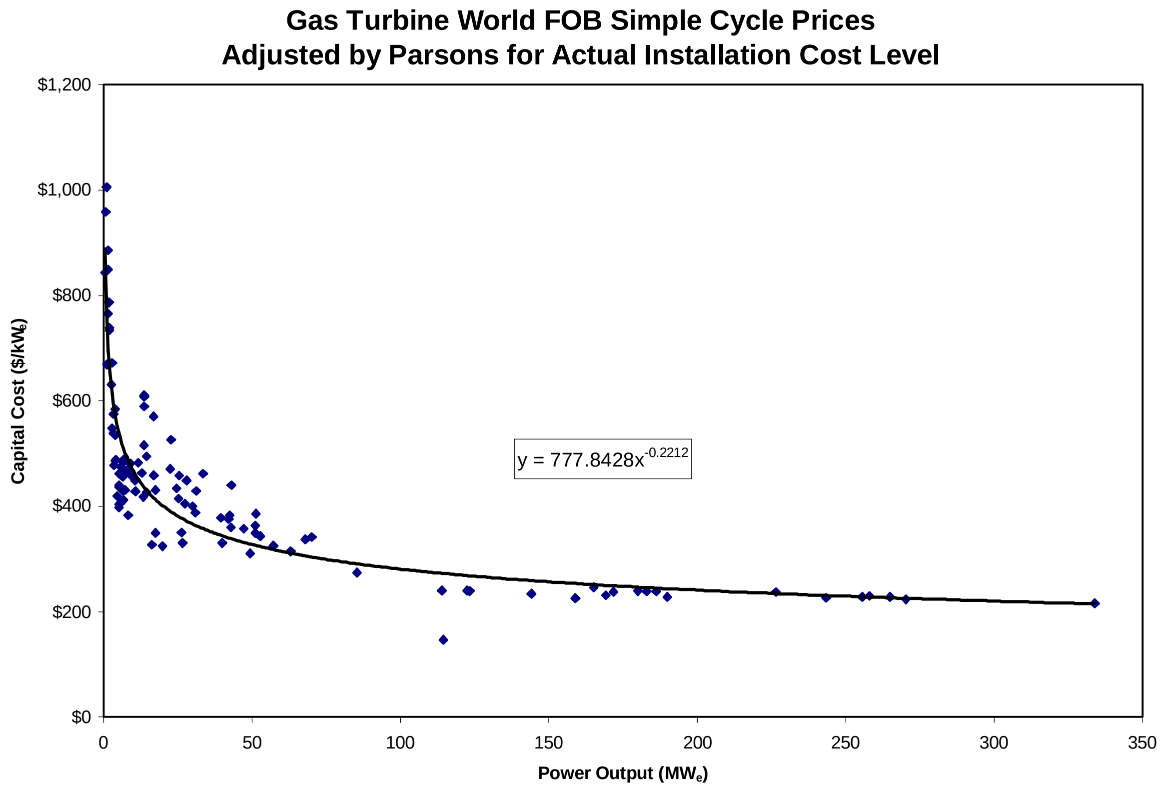
Exhibit 5-2
Gas Turbine World Simple Cycle Gas Turbine Price vs. Power Output Graph

Does NOT include adjustment to actual installed price



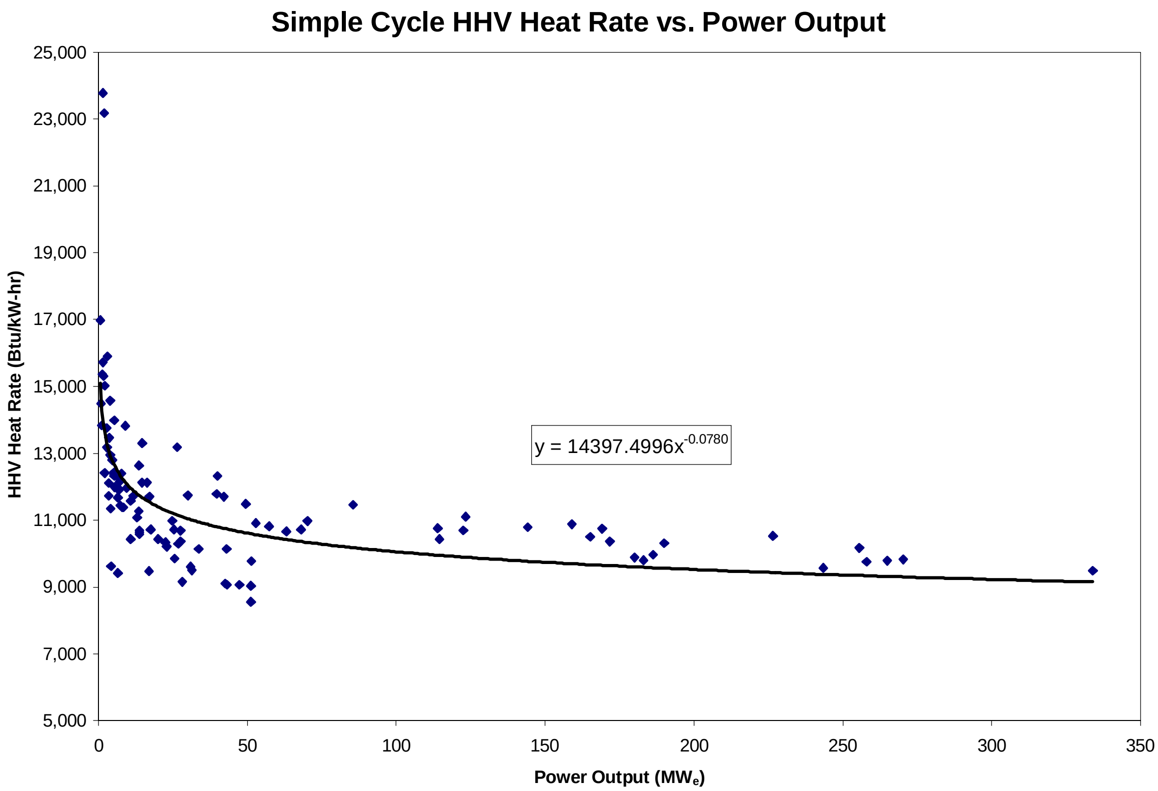
The trend line shown versus the Parsons'-adjusted data in Exhibit 5-3 is used in this market assessment as the assumed price versus size for simple cycle gas turbines.

Exhibit 5-3
Adjusted Simple Cycle Gas Turbine Installed Price vs. Power Output Graph Used for Market Assessment



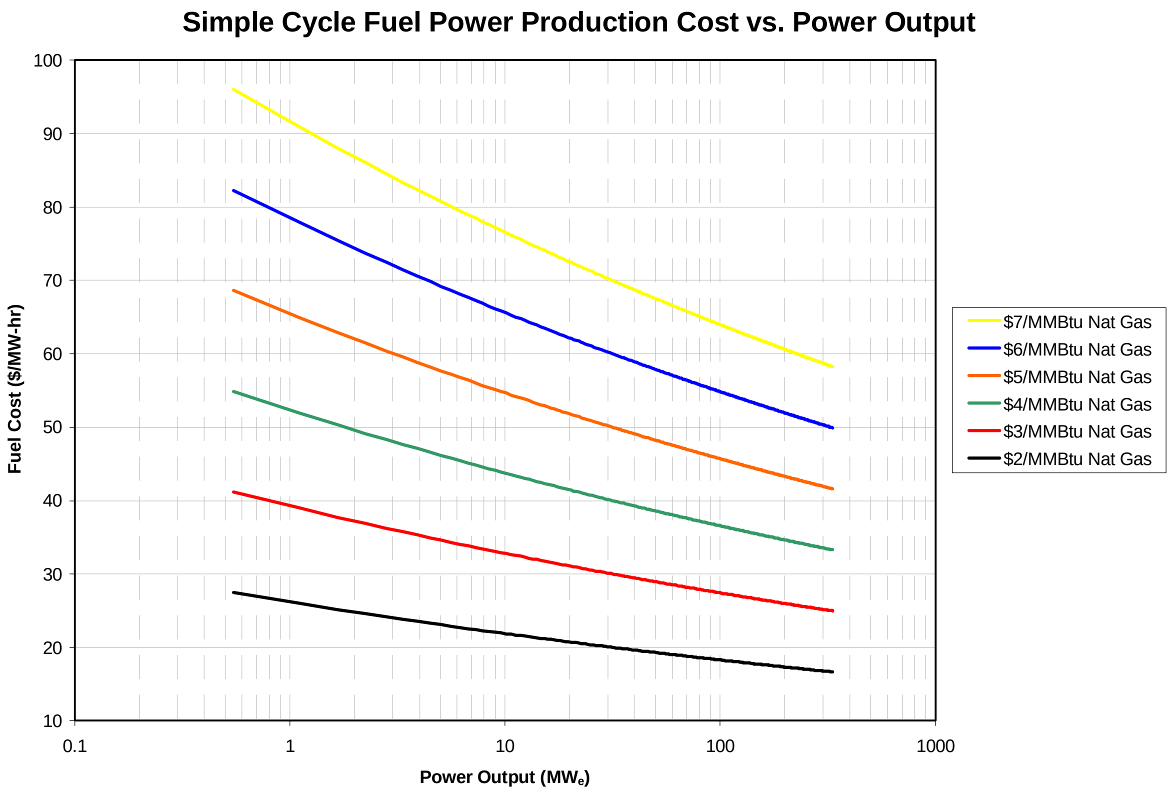
Gas Turbine Peaker Heat Rate. The simple cycle turbogenerator heat rate levels were also taken from the 1999-2000 Gas Turbine World Handbook. The data points plotted on Exhibit 5-4 show these data. A curve fit of these data, Exhibit 5-4, was used to establish the heat rate versus size relationship for simple cycle gas turbines in this market assessment.

Exhibit 5-4
Curve Fit of <u>Gas Turbine World</u> Simple Cycle Heat Rate vs. Power Output



Gas Turbine Peaker Threshold Bid Price. Heat rate and power output data were taken as described above for the Simple Cycle gas turbines and used to find the necessary thermal input to produce the ISO Base Load power. Threshold bid prices were then calculated for 6 different theoretical natural gas prices ($2 - $7/10^6 Btu, in $1 increments). All six sets of data were then plotted for comparative purposes in Exhibit 5-6.

Exhibit 5-5
Simple Cycle Power Threshold Bid Price vs. Heat Rate Graph



5.2 Combined Cycle Study Assumptions

Combined Cycle Price. These costs represent average standardized turnkey combined cycle power plant prices in 1999 U.S. dollars for a basic natural gas-fired combined cycle including:

- Gas turbine generator
- Unfired multi-pressure heat recovery boiler w/o bypass stack
- Condensing multi-pressure steam turbine generator
- Step-up transformer
- Water cooled heat rejection
- Standard controls, starting system and plant auxiliaries
- Generally with dry low NO_x gas turbine

Exhibit 5-6
<u>Gas Turbine World</u> Combined Cycle Budget Price Levels

Does NOT include adjustment to actual installed price

Combined Cycle Turnkey Plant Budget Price Levels

Plant Model	Net Plant Output (MW_e)	LHV Heat Rate (Btu/kW-hr)	Net Plant Efficiency	No. Gas Turbines	No. Steam Turbines	Budget Price	$ per kW_e
GT5 Cogen[1]	2.7	n/a	n/a	1xGT35	n/a	$2,186,000	$825
GTM7 Cogen[1]	5.7	n/a	n/a	1xM7A-01	n/a	$4,150,000	$726
STAC 60	6.6	8,810	38.7	1xTaurus 60	1x1.7MW	$4,950,000	$750
GPCS 80	7.9	8,470	40.3	1xM7A-01	1x2.4 MW, 1P	$7,900,000	$1,000
STAC 70	9.0	8,320	41.0	1xTaurus 70	1x2.1 MW	$6,750,000	$750
STAC 100	13.3	8,380	40.7	1xMars 100	1x3.2 MW	$9,975,000	$750
Aquarius-16[2]	15.5	8,020	42.5	1xUGT10000S	n/a	$6,650,000	$429
STAC 130	16.7	8,235	41.4	1xTitan 130	1x3.9 MW	$12,190,000	$730
STEG-LM116	18.7	6,870	49.7	1xLM1600	1x5.3 MW, 2P	$15,780,000	$844
KA35-1	22.8	7,880	43.3	1xGT35	1x6.2 MW, 2P	$19,100,000	$838
Aquarius-25[2]	24.3	8,220	41.5	1xUGT15000S	n/a	$8,600,000	$354
CC-201	28.3	7,670	44.5	2xPGT10	1x10 MW, 2P	$24,100,000	$852
THM1304	28.7	7,585	45.0	2x1304D	1x10.8 MW, 2P	$26,000,000	$906
CC1-2500	31.2	6,850	49.8	1xLM2500	1x8.4 MW, 2P	$25,200,000	$808
FT8	32.3	6,925	49.3	1xFT8	1x8.4 MW, 2P	$25,800,000	$799
KA10-1	36.1	6,760	50.5	1xGT10B	1x12 MW, 2P	$28,340,000	$785
CC1-2500+	38.4	6,570	51.9	1xLM2500+	1x12 MW, 2P	$27,300,000	$711
CC105P	38.5	8,180	41.7	1xFr5PA	1x13 MW, 2P	$24,620,000	$639
1xRB211-6761	38.7	6,920	49.3	1xRB211	1x11 MW, 2P	$27,475,000	$710
Aquarius-40[2]	40.1	7,750	44.0	1xUGT25000S	n/a	$11,990,000	$299
CC1-6000	56.4	6,620	51.5	1xLM6000PC	1x13 MW, 2P	$37,100,000	$658
Vega 106B	59.8	7,005	48.7	1xFr6B	1x23 MW, 2P	$38,500,000	$644
1x1 Trent	66.0	6,285	54.3	1xTrent	1x15 MW, 2P	$42,900,000	$650
FT8 Twin	67.0	6,800	50.2	2xFT8	1x18 MW, 2P	$42,200,000	$630
1xW251B11/12	71.5	7,140	47.8	1x251B11/12	1x25 MW, 2P	$49,200,000	$688
KA10-2	73.2	6,730	50.7	2xGT10B	1x25 MW, 2P	$48,500,000	$663
2xRB211-6761	77.4	6,920	49.3	2xRB211	1x22 MW, 2P	$51,860,000	$670
KA8C-1	77.4	6,740	50.6	1xGT8C	1x25 MW, 2P	$52,300,000	$676
CC205P	77.8	8,110	42.1	2xFr.5PA	1x27 MW, 2P	$47,850,000	$615
KA8C-1S	83.0	6,640	51.4	1xGT8C2	1x26 MW, 2P	$52,000,000	$627
1xP200-PFBC	100.0	8,030	42.5	1xGT35P	1x83 MW, Cond.	$100,000,000	$1,000
GUD 1S.64.3A	101.0	6,355	53.7	1xV64.3A	1x31 MW, 3P, RH	$73,700,000	$730
CC2-6000	106.5	6,610	51.6	2xLM6000PC	1x22 MW, 2P	$69,900,000	$656
S-106FA	107.4	6,420	53.1	1xFr6FA	1x40 MW, 3P, RH	$78,400,000	$730
S-206B	121.0	6,930	49.2	2xFr6B	1x43 MW, 2P	$69,500,000	$574
KA11N-1	125.4	6,820	50.0	1xGT11N	1x45 MW, 2P	$68,600,000	$547
S-107EA	130.2	6,800	50.2	1xFr7EA	1x48 MW, 3P	$67,000,000	$515
2x1 Trent	132.0	6,285	54.3	2xTrent	1x29 MW, 2P	$83,160,000	$630
2x1 251B11/12	145.4	6,990	48.8	2x251B11/12	1x53 MW, 2P	$87,200,000	$600
KA13D-1	147.1	6,920	49.3	1xGT13D	1x53 MW, 1P	$74,900,000	$509
KA11N2-1	167.0	6,700	50.9	1xGT11N2	1x56 MW, 2P	$82,600,000	$495
1xW501D5A	172.0	6,800	50.2	1x501D5A	1x59 MW, 2P	$85,900,000	$499
Cobra 264.3	183.0	6,545	52.1	1xV64.3	1x64 MW, 2P	$87,000,000	$475
S-109E	189.2	6,570	51.9	1xFr9E	1x70 MW, 2P	$90,000,000	$476
MPCP1-701D	212.5	6,635	51.4	1xM701D	1x70 MW, 2P	$99,875,000	$470
S-206FA	218.7	6,300	54.2	2xFr6FA	1x84 MW, 3P, RH	$103,000,000	$471
GUD 1.94.2	232.5	6,630	51.5	1xV94.2	1x86 MW, 2P	$106,400,000	$458
GUD 1S84.3A	260.0	5,980	57.1	1xV84.3A	1x84 MW, 3P, RH	$113,900,000	$438
S-107FA	262.6	6,090	56.0	1xFr7FA	1x95 MW, 3P, RH	$114,900,000	$438
S-207EA	263.6	6,700	50.9	2xFr7EA	1x101 MW, 3P	$115,750,000	$439
1xW501F	273.5	6,150	55.5	1xW501F	1x97 MW, 3P, RH	$113,970,000	$417
KA24-1	274.0	5,870	58.1	1xGT24	1x102 MW, 2P	$114,800,000	$419
GUD 1S.94.2A	293.5	6,180	55.2	1xV94.2A	1x95 MW, 3P, RH	$115,930,000	$395
2xW501D5A	348.3	6,770	50.4	2x501D5A	1x119 MW, 2P	$139,300,000	$400
GUD 1S.94.3A	385.5	5,980	57.1	1xV94.3A	1x120 MW, 3P, RH	$138,000,000	$358
S-109FA	390.8	6,020	56.7	1xFr9FA	1x142 MW, 3P, RH	$139,100,000	$356
KA26-1	393.0	5,830	58.5	1xGT26	1x140 MW, 3P, RH	$140,500,000	$358
1x1 M701F	397.7	5,988	57.0	1x,701F	1x132 MW, 3P, RH	$139,200,000	$350
MPCP2-701D	428.6	6,610	51.6	2xM701D	1x142 MW, 2P	$162,250,000	$379
Cobra 294.2	478.5	6,505	52.5	2xV94.2	1x178 MW, 2P	$164,000,000	$343
KA13E2-2	485.7	6,410	53.2	2xGT13E2	1x167 MW, 2P	$166,000,000	$342
KA11N2-3	517.0	6,550	52.1	3xGT11N2	1x172 MW, 2P	$178,400,000	$345
S-207FA	530.0	6,040	56.5	2xFr7FA	1x196 MW, 3P, RH	$182,500,000	$344
2xW501F	548.2	6,090	56.0	2x501F	1x196 MW, 3P, RH	$183,600,000	$335
S-507EA	620.0	6,800	50.2	5xFr7EA	3x68 MW, 3P	$207,700,000	$335
GUD 3.94.2	719.5	6,490	52.6	3xV94.2	1x270 MW, 2P	$244,700,000	$340
KA13E2-3	728.6	6,410	53.2	3xGT13E2	1x248 MW, 2P	$244,400,000	$335
GUD 2.94.3A	760.0	5,883	58.0	2xV94.3A	1x260 MW, 3P, RH	$239,700,000	$315

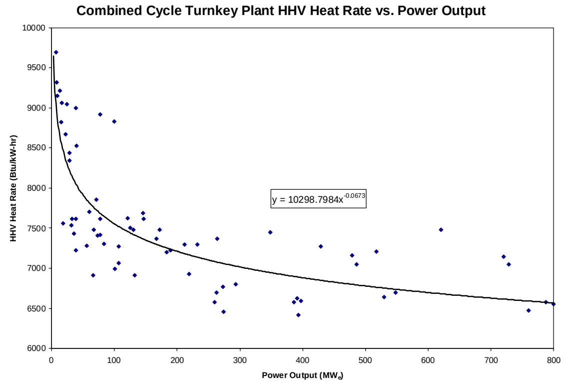
Prices can vary significantly depending on the scope of plant equipment, geographical area, special site requirements and competitive market conditions. These F.O.B. prices need to be adjusted to actual installation price.

Exhibit 5-7, to the right, is a scatter plot of data collected for Combined Cycle gas turbines as described above. The trendline is a regression analysis fit of the data. An exponential curve-fit matches the direction of the data. The data to the right represents FOB data, and must be adjusted for actual installation price.

Exhibit 5-8 is a scatter plot of Gas Turbine World FOB prices for combined cycle turnkey plant prices adjusted by Parsons to match actual installation cost levels. The trendline is a power curve fit of the data. This may not be the best option to fit the data, but it seemed to closely resemble the direction of the data.

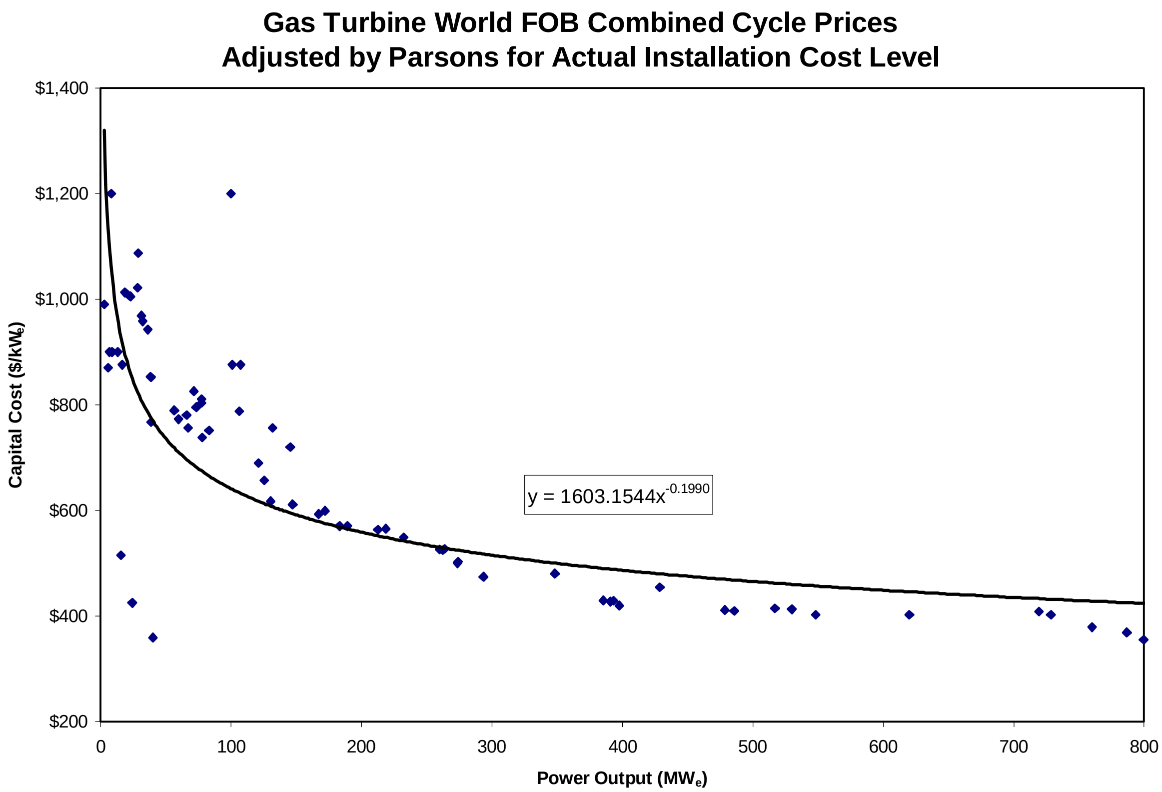
Exhibit 5-7
Gas Turbine World Combined Cycle Turnkey Plant Price vs. Power Output Graph

Does NOT include adjustment to actual installed price



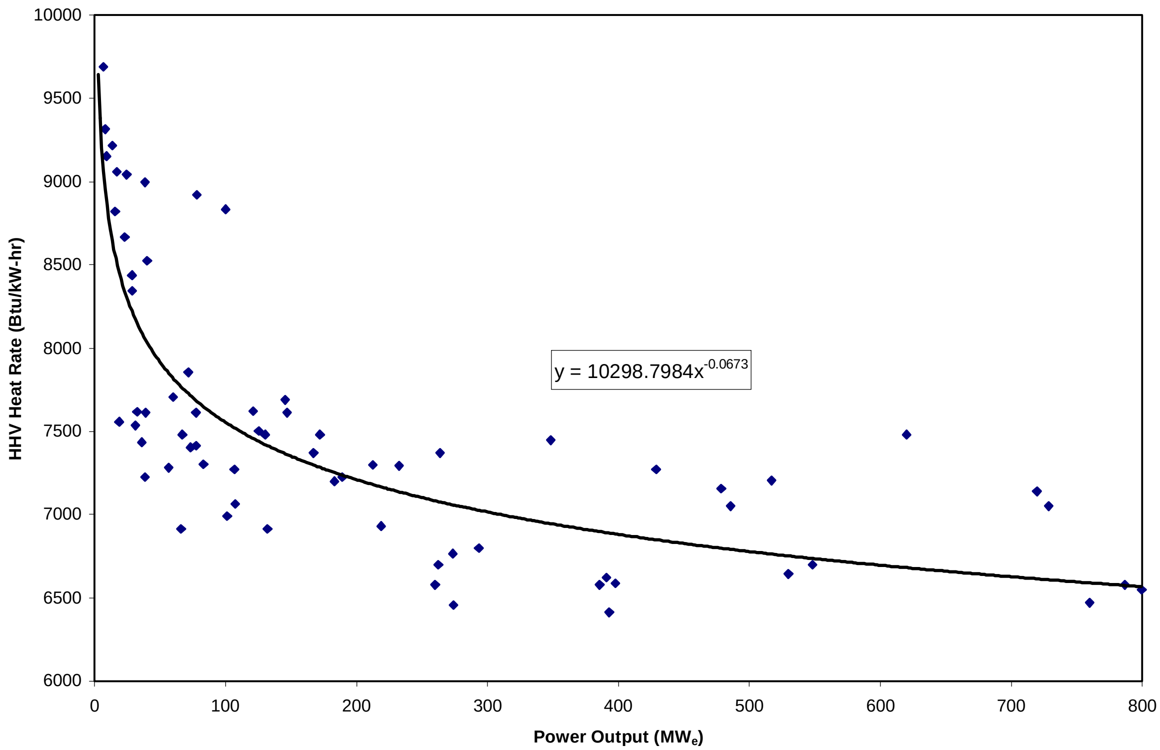
The Exhibit 5-8 curve fit provides the basis for the assessment of combined cycle price in these market evaluations.

Exhibit 5-8
Adjusted Combined Cycle Turnkey Installed Plant Price vs. Power Output Graph Used for Market Assessment



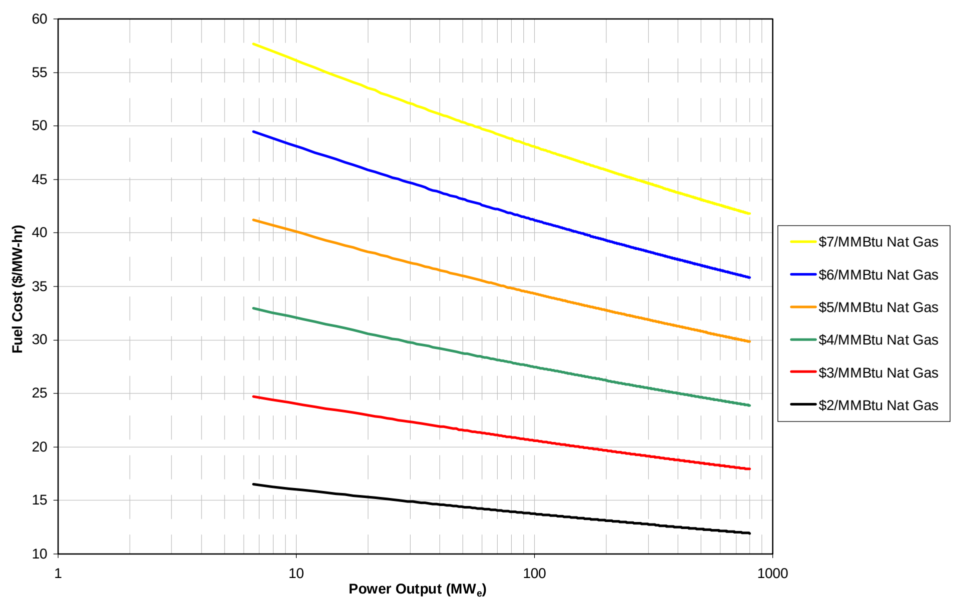
Combined Cycle Heat Rate. The combined cycle heat rate levels were also taken from the 1999-2000 Gas Turbine World Handbook. These are shown as data points in Exhibit 5-9. A curve fit of these data, Exhibit 5-9, was used to establish the heat rate versus size relationship for the combined cycles in this market assessment.

Exhibit 5-9 Combined Cycle Heat Rate vs. Power Output Graph



Combined Cycle Threshold Bid Price. In order to generate threshold bid price data, heat rate and power output data were taken as described above for the Combined Cycle turnkey plants and used to find the necessary thermal input to produce the ISO Base Load power. Threshold bid prices were then calculated for 6 different theoretical natural gas prices ($2 - $7/10^6 Btu, in $1 increments). All six sets of data were then plotted for comparative purposes in Exhibit 5-10.

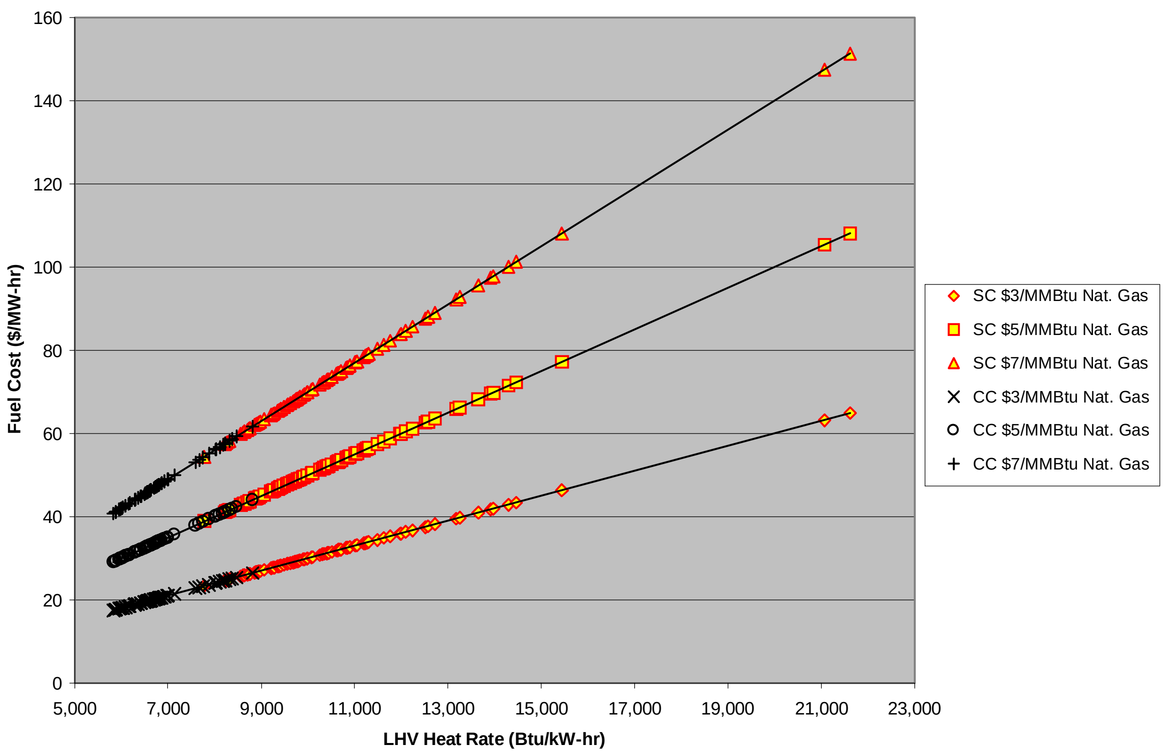
Exhibit 5-10 Combined Cycle Fuel Cost vs. Unit Size



5.3 Fuel Price vs. Heat Rate

Fuel cost per MWh varies linearly with heat rate and price. For convenience, the relationship is shown in Exhibit 5-11.

Exhibit 5-11
Fuel Cost of Simple Cycle Gas Turbine Compared to Combined Cycle

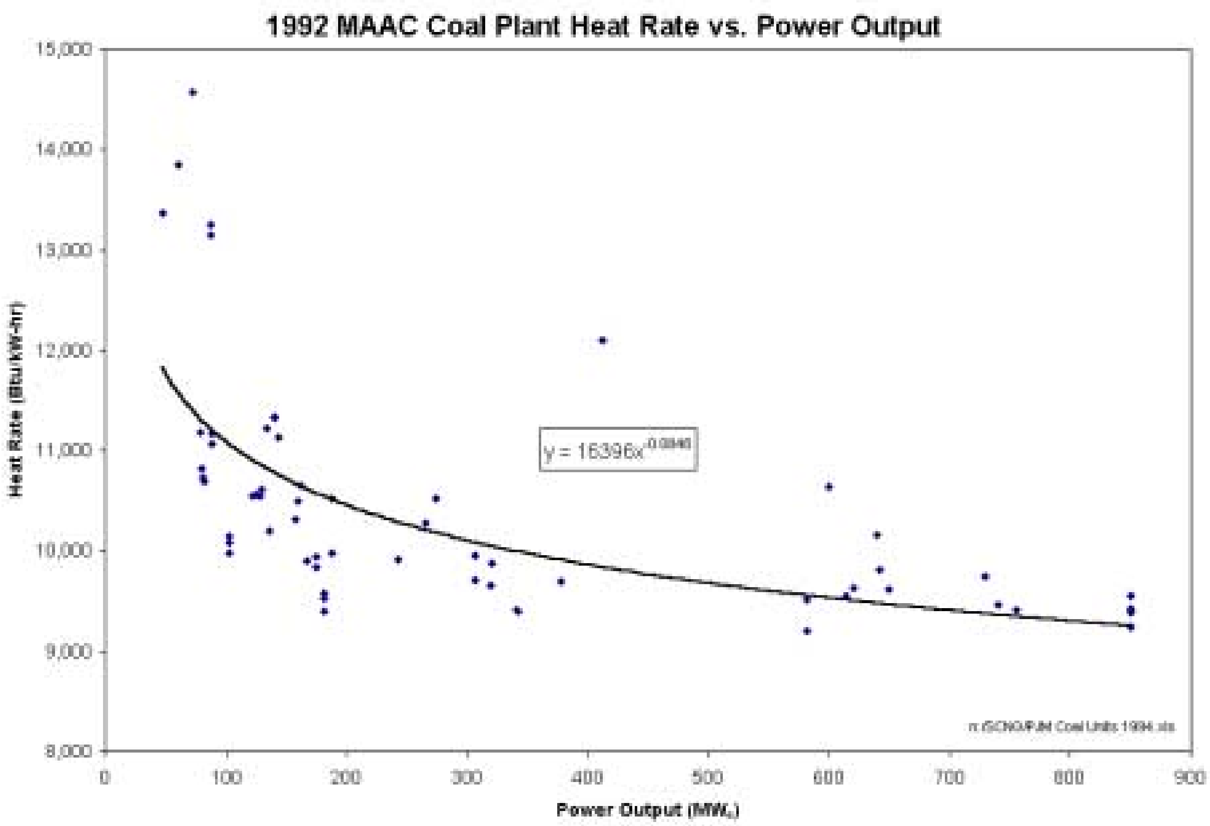


5.4 PJM Coal Fired Units

A table of all generating units in the PJM region was produced using a table of all generating units in the United States as of 1994. For the units in the database there were several entries, each for a different year of operation, though only those with data from the most recent year (1992) were used for comparative purposes. Only coal-fired plants were considered here, of which there were 74 in the database, though only 66 had entries for 1992. Five of the plants did not have a reported heat rate, so they were not considered in this comparison.

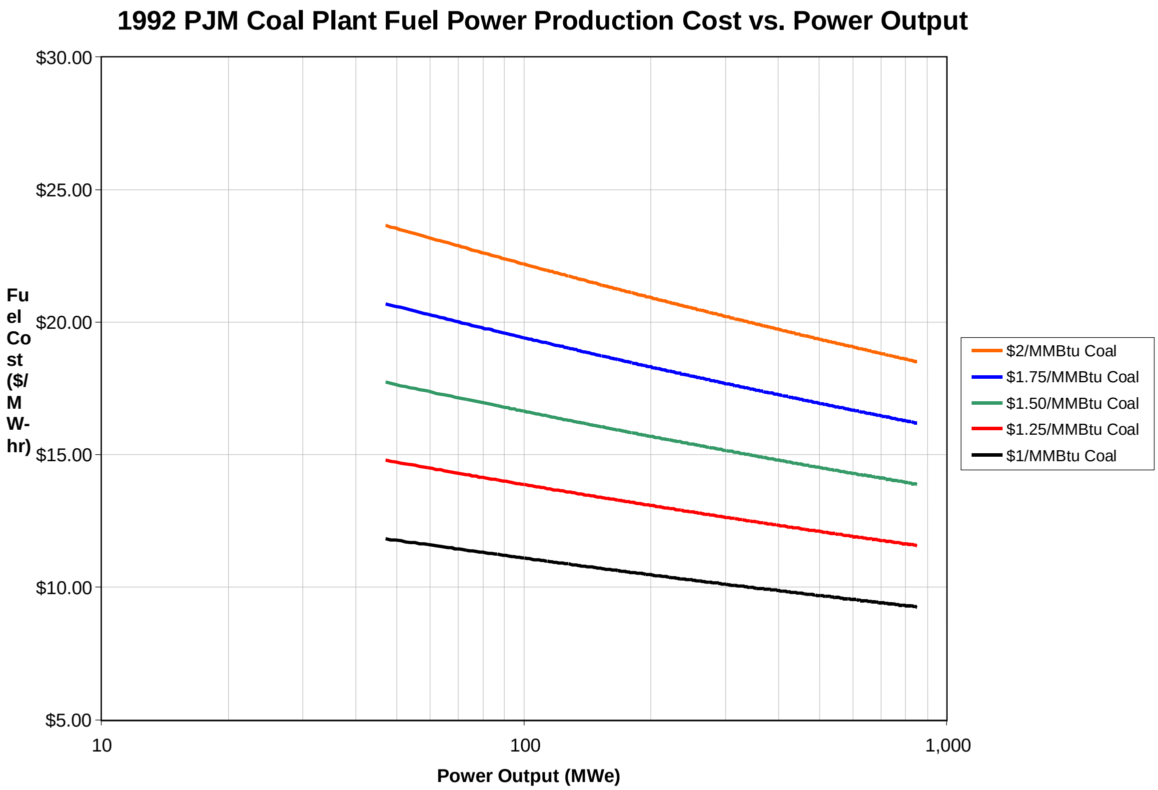
Existing Coal Unit Heat Rate. Thermal input for each of the plants was calculated from the heat rate and net power output. The number of hours each plant ran was calculated from the capacity factor (which was based on 8784 possible operating hours per year). Average heat rates for units under 100 MWe, units between 100 MWe and 500 MWe, and units over 500 MWe were then calculated from the net MW-hrs and thermal input-hrs. A curve fit of these data is shown in Exhibit 5-12.

Exhibit 5-12
The Heat Rate of the Existing Coal Plant Fleet in the PJM Region



Coal Power Threshold Bid Price vs. Heat Rate. In order to generate this data, heat rate and power output data were taken as described above for the Simple Cycle turbines and Combined Cycle turnkey plants and used to find the necessary thermal input to produce the ISO Base Load power. Threshold bid prices were then calculated for 5 different theoretical coal prices ($1 - $2/10^6 Btu, in $0.25 increments). All six sets of data were then plotted for comparative purposes.

Exhibit 5-13
Assumed PJM Coal Plant Threshold Bid Prices vs. Size



6. PJM Unit Data

The units in the PJM region were characterized using information from a number of databases. These include:

- The UDI DataBase[7].
- The EIA Inventory of Power Plants in the United States.
- The EIA Inventory of Non-Utility Electric Power Plants in the United States.
- FERC Form 1 data from FERC web site.

There are 497 units in the GEMSET unit database for the PJM region. Parsons estimated the heat rates and the variable operating costs for each of these units. Using the fuel costs discussed earlier, threshold bid price can be calculated:

(Threshold Bid Price, $/MWh) = (HR)*(FP)/1000+(Consumables)

where:
HR ....= heat rate, Btu/kWh
FP ....= fuel price, $\$/10^6$ Btu
Consumables ....= cost of consumables, $/MWh

Note: Threshold Bid Price does not include a capital component since those costs are captured in the capacity obligation prices set by PJM.

The pages that follow as Exhibit 6-1 are the baseline GEMSET data base report that shows the threshold bid price ranking of all units in PJM under the baseline assumptions. These data tabulate:

- The unit owner and unit name,
- Rating (in ascending order of estimated baseline threshold bid price (lowest cost unit first to highest last), and
- Cumulative MW making up PJM's generation.

In the GEMSET model, these units are added in this threshold bid price order to meet demand. For example, if PJM system demand were 42,600 MW, all units from the first on the list, FirstEnergy's Seneca, up to the Public Service Electric & Gas Co.'s Bergen unit (which just meets a cumulative MW of just above 42,625 MW) would be those units presumed to be operating. All units up to and including the Public Service Electric & Gas Co.'s Bergen unit are presumed used to meet that particular demand.

Exhibit 6-1
GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet

Baseline $1.35/10^6$ Btu coal -- $5.00/10^6$ Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative M
Bio- Energy Partners	Pottstown Landfill	GT	LF	5,000	6
Metropolitan Edison Co.	Modern Landfill NUG	IC	LF	8,000	14
Pennsylvania Power & Light Co.	Keystone Landfill	IC	LF	5,000	19
Public Service Electric & Gas Co.	O'brien Edgeboro	ST	LF	9,000	28
PEI Power Corporation	Archibald NUG	ST	LF	19,000	47
Public Service Electric & Gas Co.	Wheelab	ST	MW	48,000	95
Public Service Electric & Gas Co.	Ess Co Rr	ST	MW	65,000	160
Public Service Electric & Gas Co.	Union Co	ST	MW	39,000	199
Jersey Central Power& Light Co.	Camden County Rr NUG	ST	MW	23,000	222
Metropolitan Edison Co.	Lancaster Co RR NUG	ST	MW	30,000	252
Jersey Central Power& Light Co.	L & D Landfill NUG	NA	MW	2,000	254
Pennsylvania Power & Light Co.	Harrisburg	ST	MW	6,000	260
Jersey Central Power& Light Co.	Warren County Rr NUG	ST	MW	10,000	270
Sithe Power Marketing, L. P.	Piney	HY	WAT	9,000	280
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	290
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	11,000	301
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	11,000	312
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	322
Sithe Power Marketing, L. P.	Piney	HY	WAT	9,000	331
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	341
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	351
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	361
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	371
Pennsylvania Power & Light Co.	Wallenpaupack	HY	WAT	22,000	393
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	403
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	10,000	413
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	32,000	445
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	37,500	482
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	33,000	515
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	32,000	547
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	32,000	579
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	32,000	611
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	37,500	649
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	32,000	681
Sithe Power Marketing, L. P.	Piney	HY	WAT	9,000	690
Public Service Electric & Gas Co.	Gr. Falls	HY	WAT	11,000	701
Sithe Power Marketing, L. P.	Deep Creek	HY	WAT	9,000	711
Pennsylvania Power & Light Co.	Wallenpaupack	HY	WAT	22,000	733
Sithe Power Marketing, L. P.	Deep Creek	HY	WAT	9,000	742
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	500	742
Pennsylvania Power & Light Co.	Holtwood	HY	WAT	500	743

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6$ Btu coal -- $5.00/10^6$ Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	33,000	776
Metropolitan Edison Co.	York Haven	HY	WAT	19,000	795
PECO Energy	Conowingo	HY	WAT	36,000	831
PECO Energy	Conowingo	HY	WAT	36,000	867
PECO Energy	Conowingo	HY	WAT	36,000	903
PECO Energy	Conowingo	HY	WAT	36,000	939
PECO Energy	Conowingo	HY	WAT	36,000	975
PECO Energy	Conowingo	HY	WAT	65,000	1,040
PECO Energy	Conowingo	HY	WAT	36,000	1,076
PECO Energy	Conowingo	HY	WAT	65,000	1,141
Jersey Central Power& Light Co.	Yards Creek	PS	WAT	120,000	1,261
Jersey Central Power& Light Co.	Yards Creek	PS	WAT	140,000	1,401
Jersey Central Power& Light Co.	Yards Creek	PS	WAT	140,000	1,541
FirstEnergy Corporation	Seneca	PS	WAT	30,000	1,573
FirstEnergy Corporation	Seneca	PS	WAT	195,000	1,770
FirstEnergy Corporation	Seneca	PS	WAT	210,000	1,980
PECO Energy	Conowingo	HY	WAT	36,000	2,016
PECO Energy	Muddy Run	PS	WAT	110,000	2,126
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	37,500	2,163
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	38,500	2,202
Pennsylvania Electric Co.	Raystown	HY	WAT	6,000	2,214
Pennsylvania Electric Co.	Conemaugh Dam NUG	NA	WAT	4,000	2,222
PECO Energy	Conowingo	HY	WAT	65,000	2,287
PECO Energy	Muddy Run	PS	WAT	110,000	2,397
Safe Harbor Water Power Corp.	Safe Harbor	HY	WAT	38,500	2,435
PECO Energy	Muddy Run	PS	WAT	110,000	2,545
PECO Energy	Muddy Run	PS	WAT	120,000	2,665
PECO Energy	Muddy Run	PS	WAT	110,000	2,775
PECO Energy	Muddy Run	PS	WAT	120,000	2,895
PECO Energy	Muddy Run	PS	WAT	110,000	3,005
PECO Energy	Conowingo	HY	WAT	65,000	3,070
PECO Energy	Muddy Run	PS	WAT	120,000	3,190
Pennsylvania Electric Co.	Colver NUG	SF	BG	104,000	3,294
Pennsylvania Electric Co.	Cambria NUG	SF	BG	88,000	3,382
Schuylkill Energy Resources, Inc.	Schuylkill Energy	AB	CULM	86,000	3,470
Pennsylvania Power & Light Co.	Gilberton Power	AB	CULM	82,000	3,552
Pennsylvania Electric Co.	Scrubgrass NUG	SF	BG	80,000	3,632
Pennsylvania Power & Light Co.	Northeast Power Co	AB	CULM	52,000	3,684
Pennsylvania Electric Co.	Ebensburg NUG	SF	BG	50,000	3,734
Pennsylvania Power & Light Co.	Frackville	AB	CULM	43,000	3,777
Pennsylvania Power & Light Co.	Foster Wheeler	AB	CULM	43,000	3,820
Pennsylvania Electric Co.	Piney Creek NUG	SF	BG	31,000	3,851

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6 Btu coal -- $5.00/10^6 Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Delmarva Power / Conectiv	Hay Road	CW	WH	175,000	4,026
Sithe Power Marketing, L. P.	Gilbert	CW	WH	90,000	4,130
Pennsylvania Power & Light Co.	Viking Energy	ST	WW	17,000	4,147
Pennsylvania Power & Light Co.	Koopers Co.	ST	RT	8,000	4,155
Public Service Electric & Gas Co.	Burlington	CW	WH	56,000	4,220
PECO Energy	Limerick	NB	UR	1,134,000	5,402
PECO Energy	Limerick	NB	UR	1,150,000	6,600
GPU Nuclear Corp	Oyster Creek	NB	UR	619,000	7,237
PECO Energy	Peach Bottom	NB	UR	1,093,000	8,356
PECO Energy	Peach Bottom	NB	UR	1,093,000	9,475
AmerGen Energy Company, L. L. C.	Three Mile Island	NB	UR	786,000	10,285
Pennsylvania Power & Light Co.	Susquehanna	NB	UR	1,090,000	11,392
Pennsylvania Power & Light Co.	Susquehanna	NB	UR	1,094,000	12,502
Public Service Electric & Gas Co.	Salem	NP	UR	1,106,000	13,622
Public Service Electric & Gas Co.	Salem	NP	UR	1,106,000	14,742
Baltimore Gas & Electric Co	Calvert Cliffs	NP	UR	847,000	15,607
Baltimore Gas & Electric Co	Calvert Cliffs	NP	UR	838,000	16,472
PECO Energy	Greys Ferry NUG	CW	WH	32,000	16,504
Public Service Electric & Gas Co.	Hope Creek	NB	UR	1,031,000	17,577
Potomac Electric Power Co.	Morgantown	ST	COAL	582,000	18,160
Pennsylvania Power & Light Co.	Montour	ST	COAL	745,000	18,915
Pennsylvania Power & Light Co.	Montour	ST	COAL	745,000	19,670
Sithe Power Marketing, L. P.	Keystone	ST	COAL	850,000	20,520
Potomac Electric Power Co.	Chalk Point	ST	COAL	341,000	20,861
Potomac Electric Power Co.	Dickerson	ST	COAL	182,000	21,043
Potomac Electric Power Co.	Chalk Point	ST	COAL	342,000	21,386
Sithe Power Marketing, L. P.	Conemaugh	ST	COAL	850,000	22,236
Sithe Power Marketing, L. P.	Conemaugh	ST	COAL	850,000	23,086
Potomac Electric Power Co.	Morgantown	ST	COAL	582,000	23,669
Potomac Electric Power Co.	Dickerson	ST	COAL	182,000	23,851
Sithe Power Marketing, L. P.	Keystone	ST	COAL	850,000	24,701
Edison Mission M. & T, Inc.	Homer City	ST	COAL	620,000	25,321
Potomac Electric Power Co.	Dickerson	ST	COAL	182,000	25,503
Edison Mission M. & T, Inc.	Homer City	ST	COAL	650,000	26,153
Edison Mission M. & T, Inc.	Homer City	ST	COAL	614,000	26,767
Baltimore Gas & Electric Co	Herbert A Wagner	ST	COAL	324,000	27,099
Pennsylvania Power & Light Co.	Brunner Island	ST	COAL	321,000	27,433
Public Service Electric & Gas Co.	Mercer	ST	COAL	324,000	27,758
Delmarva Power / Conectiv	Delaware City	ST	PC	28,500	27,787
Delmarva Power / Conectiv	Delaware City	ST	PC	28,500	27,815
Pennsylvania Power & Light Co.	Brunner Island	ST	COAL	735,000	28,560
Baltimore Gas & Electric Co	Brandon Shores	ST	COAL	650,000	29,230

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6 Btu coal -- $5.00/10^6 Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Sithe Power Marketing, L. P.	Shawville	ST	COAL	125,000	29,360
Pennsylvania Power & Light Co.	Brunner Island	ST	COAL	378,000	29,750
Delmarva Power / Conectiv	Edge Moor	ST	COAL	86,000	29,836
Sithe Power Marketing, L. P.	Portland	ST	COAL	158,000	29,994
Sithe Power Marketing, L. P.	Shawville	ST	COAL	122,000	30,122
Public Service Electric & Gas Co.	Mercer	ST	COAL	324,000	30,447
Baltimore Gas & Electric Co	C P Crane	ST	COAL	195,000	30,642
Potomac Electric Power Co.	Potomac River	ST	COAL	88,000	30,730
Potomac Electric Power Co.	Potomac River	ST	COAL	102,000	30,832
Potomac Electric Power Co.	Potomac River	ST	COAL	88,000	30,920
Baltimore Gas & Electric Co	Brandon Shores	ST	COAL	650,000	31,590
Sithe Power Marketing, L. P.	Seward	ST	COAL	60,000	31,652
Atlantic Electric / Conectiv	CCLP NUG	ST	COL	245,000	31,897
Sithe Power Marketing, L. P.	Portland	ST	COAL	243,000	32,140
Atlantic Electric / Conectiv	Logan (KCS)	ST	COAL	219,000	32,359
Atlantic Electric / Conectiv	B L England	ST	COAL	129,000	32,488
Baltimore Gas & Electric Co	C P Crane	ST	COAL	190,000	32,678
PECO Energy	Eddystone	ST	COAL	302,000	32,989
Sithe Power Marketing, L. P.	Shawville	ST	COAL	175,000	33,169
Sithe Power Marketing, L. P.	Shawville	ST	COAL	175,000	33,349
Atlantic Electric / Conectiv	B L England	ST	COAL	155,000	33,509
Public Service Electric & Gas Co.	Hudson	ST	COAL	383,000	33,914
Delmarva Power / Conectiv	Indian River	ST	COAL	165,000	34,079
Delmarva Power / Conectiv	Edge Moor	ST	COAL	174,000	34,253
Sithe Power Marketing, L. P.	Titus	ST	COAL	81,000	34,336
Sithe Power Marketing, L. P.	Titus	ST	COAL	81,000	34,419
Sunbury Generation, L. L. C.	Sunbury	ST	COAL	128,000	34,553
Sunbury Generation, L. L. C.	Sunbury	CH	COAL	94,000	34,656
Delmarva Power / Conectiv	Indian River	ST	COAL	91,000	34,747
PECO Energy	Cromby	ST	COAL	144,000	34,894
Delmarva Power / Conectiv	Indian River	ST	COAL	91,000	34,985
Sithe Power Marketing, L. P.	Titus	ST	COAL	81,000	35,068
Baltimore Gas & Electric Co	Herbert A Wagner	ST	COAL	135,000	35,203
Atlantic Electric / Conectiv	Deepwater	ST	BIT	80,000	35,284
Metropolitan Edison Co.	Panther Creek NUG	SF	AC	80,000	35,364
Pennsylvania Power & Light Co.	Martins Creek	ST	COAL	140,000	35,514
Pennsylvania Power & Light Co.	Martins Creek	ST	COAL	140,000	35,664
Atlantic Electric / Conectiv	DRMI	ST	COL	75,000	35,739
Baltimore Gas & Electric Co	Bresco NUG	ST	COL	57,000	35,796
Delmarva Power / Conectiv	Delaware City	ST	PC	48,000	35,844
Delmarva Power / Conectiv	Indian River	ST	COAL	420,000	36,264
Metropolitan Edison Co.	P. H. Glatfelter NUG	ST	COAL	35,000	36,299

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6$ Btu coal -- $5.00/10^6$ Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Sunbury Generation, L. L. C.	Sunbury	CH	COAL	70,000	36,375
Sunbury Generation, L. L. C.	Sunbury	CH	COAL	70,000	36,451
Cinergy Capital & Trading, Inc.	Westwood NUG	ST	AC	30,000	36,481
PECO Energy	MMLP NUG	ST	COL	28,000	36,509
Dover City Of	General Foods	ST	COL	16,100	36,525
Pennsylvania Power & Light Co.	Montour	ST	COAL	15,000	36,540
Potomac Electric Power Co.	Potomac River	ST	COAL	102,000	36,642
Potomac Electric Power Co.	Potomac River	ST	COAL	102,000	36,744
Pennsylvania Power & Light Co.	Holtwood	ST	COAL	-	36,744
UGI Corp.	Hunlock Power Sta	ST	COAL	48,000	36,792
Sithe Power Marketing, L. P.	Warren	ST	COAL	41,000	36,833
Sithe Power Marketing, L. P.	Warren	ST	COAL	41,000	36,874
Atlantic Electric / Conectiv	Mobil NUG	ST	COL	10,700	36,885
Atlantic Electric / Conectiv	Mobil NUG	ST	COL	10,700	36,896
Sithe Power Marketing, L. P.	Seward	ST	COAL	136,000	37,033
Public Service Electric & Gas Co.	Bergen	CT	GAS	445,000	37,478
Pennsylvania Power & Light Co.	Martins Creek	IC	FO2	2,500	37,480
Pennsylvania Power & Light Co.	Martins Creek	IC	FO2	2,500	37,483
Public Service Electric & Gas Co.	Bergen	CW	GAS	230,000	37,713
Public Service Electric & Gas Co.	Burlington	GT	NG	184,000	37,925
Public Service Electric & Gas Co.	Eagle Point	CC	GAS	195,000	38,145
Public Service Electric & Gas Co.	Essex	GT	NG	168,000	38,339
Potomac Electric Power Co.	Dickerson	GT	NG	139,000	38,506
Potomac Electric Power Co.	Dickerson	GT	NG	139,000	38,673
Public Service Electric & Gas Co.	Kearny	GT	NG	134,000	38,832
Public Service Electric & Gas Co.	Kearny	GT	NG	134,000	38,991
Public Service Electric & Gas Co.	Camden	CC	GAS	149,000	39,150
Public Service Electric & Gas Co.	Newark Bay	CC	GAS	123,000	39,297
Pedricktown Cogeneration Limited	PCLP	GT	NG	116,000	39,413
Public Service Electric & Gas Co.	Kearny	GT	KER	215,000	39,671
Potomac Electric Power Co.	Panda NUG	GT	FO1	230,000	39,901
Public Service Electric & Gas Co.	Burlington	GT	KER	184,000	40,113
Delmarva Power / Conectiv	Hay Road	CT	NG	112,000	40,235
Delmarva Power / Conectiv	Hay Road	CT	NG	112,000	40,357
Delmarva Power / Conectiv	Hay Road	CT	NG	112,000	40,479
Sithe Power Marketing, L. P.	Gilbert	GT	FO1	152,000	40,662
Sithe Power Marketing, L. P.	Portland	GT	FO1	134,000	40,818
Public Service Electric & Gas Co.	Bayonne Cogen Tech	CC	GAS	158,000	40,976
PECO Energy	Greys Ferry NUG	CT	FO1	118,000	41,094
Potomac Electric Power Co.	Chalk Point	GT	NG	85,000	41,193
Potomac Electric Power Co.	Chalk Point	GT	NG	85,000	41,292
Public Service Electric & Gas Co.	Essex	GT	NG	81,000	41,385

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6$ Btu coal -- $5.00/10^6$ Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Potomac Electric Power Co.	SMECO	GT	NG	84,000	41,478
Public Service Electric & Gas Co.	Linden	GT	NG	78,000	41,570
Sithe Power Marketing, L. P.	Sayreville	GT	NG	57,000	41,647
Sithe Power Marketing, L. P.	Sayreville	GT	GAS	57,000	41,724
Sithe Power Marketing, L. P.	Wayne	GT	NG	56,000	41,800
Sithe Power Marketing, L. P.	Werner	GT	NG	53,000	41,873
Sithe Power Marketing, L. P.	Werner	GT	NG	53,000	41,946
Sithe Power Marketing, L. P.	Werner	GT	NG	53,000	42,019
Sithe Power Marketing, L. P.	Sayreville	GT	GAS	53,000	42,092
Williams Energy M. & T. Co.	Hazelton	GT	NG	63,000	42,155
Potomac Electric Power Co.	MUNI. SOLID WASTE NUG	GT	NG	50,000	42,205
FPL Energy Power Marketing, Inc.	MH	GT	NG	45,000	42,254
Baltimore Gas & Electric Co	Bethlehem Steel NUG	ST	NG	150,000	42,404
Atlantic Electric / Conectiv	Deepwater	ST	NG	86,000	42,491
Public Service Electric & Gas Co.	Linden	GT	NG	23,000	42,521
Public Service Electric & Gas Co.	Linden	GT	NG	23,000	42,551
Sithe Power Marketing, L. P.	Blossburg	GT	NG	19,000	42,577
Atlantic Electric / Conectiv	Deepwater	GT	NG	19,000	42,601
Public Service Electric & Gas Co.	Bergen	GT	NG	21,000	42,625
Public Service Electric & Gas Co.	Linden	GT	NG	21,000	42,649
Atlantic Electric / Conectiv	Mobil NUG	GT	NG	22,100	42,671
Sithe Power Marketing, L. P.	Conemaugh	IC	FO1	2,700	42,673
Sithe Power Marketing, L. P.	Conemaugh	IC	FO1	2,700	42,676
Sithe Power Marketing, L. P.	Conemaugh	IC	FO1	2,700	42,679
Sithe Power Marketing, L. P.	Conemaugh	IC	FO1	2,700	42,681
Sithe Power Marketing, L. P.	Warren	GT	FO1	57,000	42,760
Sithe Power Marketing, L. P.	Sayreville	GT	OIL	57,000	42,837
Jersey Central Power& Light Co.	Kenilworth NUG	GT	GAS	15,000	42,852
Sithe Power Marketing, L. P.	Keystone	IC	FO1	2,700	42,855
Sithe Power Marketing, L. P.	Keystone	IC	FO1	2,700	42,858
Sithe Power Marketing, L. P.	Keystone	IC	FO1	2,700	42,860
Sithe Power Marketing, L. P.	Keystone	IC	FO1	2,700	42,863
Sithe Power Marketing, L. P.	Gilbert	CT	FO1	51,000	42,933
Sithe Power Marketing, L. P.	Gilbert	CT	FO1	49,000	43,003
Sithe Power Marketing, L. P.	Gilbert	CT	FO1	49,000	43,073
Potomac Electric Power Co.	Morgantown	GT	FO2	54,000	43,138
Potomac Electric Power Co.	Morgantown	GT	FO2	54,000	43,203
Potomac Electric Power Co.	Morgantown	GT	FO2	54,000	43,268
Potomac Electric Power Co.	Morgantown	GT	FO2	54,000	43,333
Delmarva Power / Conectiv	Edge Moor	ST	OIL	445,000	43,778
Baltimore Gas & Electric Co	Perryman	GT	FO2	52,000	43,839
Baltimore Gas & Electric Co	Perryman	GT	FO2	52,000	43,900

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6 Btu coal -- $5.00/10^6 Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Baltimore Gas & Electric Co	Perryman	GT	FO2	52,000	43,961
Baltimore Gas & Electric Co	Perryman	GT	FO2	52,000	44,022
Public Service Electric & Gas Co.	Linden	GT	NG	78,000	44,114
PECO Energy	Eddystone	ST	OIL	380,000	44,494
Baltimore Gas & Electric Co	Perryman	GT	NG	142,000	44,667
Delmarva Power / Conectiv	Crisfield	IC	FO2	2,500	44,670
Delmarva Power / Conectiv	Crisfield	IC	FO2	2,500	44,672
Delmarva Power / Conectiv	Crisfield	IC	FO2	2,500	44,675
Delmarva Power / Conectiv	Crisfield	IC	FO2	2,500	44,677
Atlantic Electric / Conectiv	Middle	GT	KER	37,000	44,721
Dover City Of	Van Sant Station	GT	FO2	39,000	44,761
Delmarva Power / Conectiv	Bayview	IC	FO2	2,000	44,763
Delmarva Power / Conectiv	Bayview	IC	FO2	2,000	44,765
Delmarva Power / Conectiv	Bayview	IC	FO2	2,000	44,767
Delmarva Power / Conectiv	Bayview	IC	FO2	2,000	44,769
Delmarva Power / Conectiv	Bayview	IC	FO2	2,000	44,771
Delmarva Power / Conectiv	Bayview	IC	FO2	2,000	44,773
Public Service Electric & Gas Co.	Sewaren	ST	GAS	118,000	44,893
PECO Energy	Fairless Hills	ST	NG	30,000	44,923
PECO Energy	Fairless Hills	ST	NG	30,000	44,953
Potomac Electric Power Co.	Chalk Point	GT	FO2	30,000	44,988
Jersey Central Power& Light Co.	MCRC (Monmouth)	GT	NG	7,000	44,995
PECO Energy	Cromby	ST	GAS	201,000	45,206
Vineland City Of	West Station	GT	FO2	26,000	45,238
Sithe Power Marketing, L. P.	Gilbert	GT	FO1	25,000	45,269
Sithe Power Marketing, L. P.	Gilbert	GT	FO1	25,000	45,300
Sithe Power Marketing, L. P.	Gilbert	GT	FO1	25,000	45,331
Sithe Power Marketing, L. P.	Gilbert	GT	FO1	23,000	45,362
Public Service Electric & Gas Co.	Hudson	ST	GAS	608,000	45,982
Sithe Power Marketing, L. P.	Sayreville	ST	GAS	90,000	46,075
Sithe Power Marketing, L. P.	Mountain	GT	FO1	20,000	46,102
Sithe Power Marketing, L. P.	Tolna	GT	FO1	20,000	46,129
Sithe Power Marketing, L. P.	Tolna	GT	FO1	20,000	46,156
Sithe Power Marketing, L. P.	Hunterstown	GT	FO1	20,000	46,183
Sithe Power Marketing, L. P.	Hunterstown	GT	FO1	20,000	46,210
Sithe Power Marketing, L. P.	Mountain	GT	FO1	20,000	46,237
Sithe Power Marketing, L. P.	Hunterstown	GT	FO1	20,000	46,264
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,290
Sithe Power Marketing, L. P.	Shawnee	GT	FO1	20,000	46,316
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,342
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,368
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,394

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6 Btu coal -- $5.00/10^6 Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,420
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,446
Sithe Power Marketing, L. P.	Hamilton	GT	FO1	20,000	46,472
Sithe Power Marketing, L. P.	Ortanna	GT	FO1	20,000	46,498
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,524
Sithe Power Marketing, L. P.	Glen Gardner	GT	FO1	20,000	46,550
Sithe Power Marketing, L. P.	Portland	GT	FO1	20,000	46,576
Atlantic Electric / Conectiv	Cedar	GT	KER	22,000	46,602
Public Service Electric & Gas Co.	Burlington	GT	KER	21,000	46,626
Pennsylvania Electric Co.	Lakeview NUG	GT	NG	5,000	46,631
Jersey Central Power& Light Co.	Manchester NUG	GT	NG	5,000	46,636
Pennsylvania Power & Light Co.	Martins Creek	ST	OIL	820,000	47,456
PECO Energy	Eddystone	GT	FO2	17,000	47,476
Sithe Power Marketing, L. P.	Titus	GT	FO1	16,000	47,496
Potomac Electric Power Co.	Morgantown	GT	FO2	16,000	47,516
Sithe Power Marketing, L. P.	Titus	GT	FO1	15,000	47,535
Sithe Power Marketing, L. P.	Portland	GT	FO1	15,000	47,554
PECO Energy	Delaware	GT	FO2	13,000	47,572
PECO Energy	Delaware	GT	FO2	13,000	47,590
PECO Energy	Eddystone	GT	FO2	13,000	47,608
PECO Energy	Eddystone	GT	FO2	13,000	47,626
PECO Energy	Delaware	GT	FO2	13,000	47,644
Potomac Electric Power Co.	Chalk Point	GT	FO2	18,000	47,662
Pennsylvania Power & Light Co.	Martins Creek	ST	OIL	820,000	48,482
PECO Energy	Southwark	GT	FO2	13,000	48,500
PECO Energy	Southwark	GT	FO2	13,000	48,518
PECO Energy	Southwark	GT	FO2	13,000	48,536
PECO Energy	Southwark	GT	FO2	13,000	48,554
PECO Energy	Pennsbury	GT	NG	2,650	48,557
PECO Energy	Pennsbury	GT	NG	2,650	48,561
Atlantic Electric / Conectiv	Cumberland	GT	NG	84,000	48,657
Atlantic Electric / Conectiv	B L England	ST	OIL	155,000	48,812
Sithe Power Marketing, L. P.	Sayreville	ST	GAS	95,000	48,909
Potomac Electric Power Co.	Chalk Point	GT	NG	107,000	49,029
Potomac Electric Power Co.	Chalk Point	GT	NG	107,000	49,149
Baltimore Gas & Electric Co	Herbert A Wagner	ST	NG	137,000	49,287
Baltimore Gas & Electric Co	Riverside	ST	NG	78,000	49,366
Statoil Energy Trading, Inc.	Paxton Creek Cogen	GT	FO1	12,000	49,378
Atlantic Electric / Conectiv	Sherman Avenue	GT	NG	81,000	49,474
Potomac Electric Power Co.	Chalk Point	ST	OIL	612,000	50,086
Metropolitan Edison Co.	York County RR NUG	ST	FO1	30,000	50,116
Delmarva Power / Conectiv	Vienna	ST	OIL	153,000	50,272

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6 Btu coal -- $5.00/10^6 Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Public Service Electric & Gas Co.	Essex	GT	NG	184,000	50,484
Public Service Electric & Gas Co.	Essex	GT	NG	184,000	50,696
Potomac Electric Power Co.	Chalk Point	ST	OIL	612,000	51,308
Vineland City Of	Howard Down	ST	FO6	23,000	51,331
Delmarva Power / Conectiv	Vienna	GT	NG	17,000	51,352
Jersey Central Power& Light Co.	Forked River	GT	FO2	34,000	51,396
Jersey Central Power& Light Co.	Forked River	GT	FO2	32,000	51,438
Public Service Electric & Gas Co.	Sewaren	ST	GAS	107,000	51,547
Public Service Electric & Gas Co.	Edison	GT	NG	168,000	51,741
Public Service Electric & Gas Co.	Edison	GT	NG	168,000	51,935
Public Service Electric & Gas Co.	Edison	GT	NG	168,000	52,129
Dover City Of	McKee Run	ST	OIL	17,000	52,146
Public Service Electric & Gas Co.	Sewaren	ST	GAS	124,000	52,273
PECO Energy	Delaware	ST	OIL	126,000	52,401
Vineland City Of	Howard Down	ST	FO6	17,000	52,418
Sithe Power Marketing, L. P.	Gilbert	CT	FO1	49,000	52,488
Potomac Electric Power Co.	Dickerson	GT	FO2	13,000	52,501
Atlantic Electric / Conectiv	Mickleton	GT	NG	59,000	52,580
Pennsylvania Power & Light Co.	West Shore	GT	FO2	14,000	52,598
Pennsylvania Power & Light Co.	Williamsport	GT	FO2	14,000	52,616
Pennsylvania Power & Light Co.	West Shore	GT	FO2	14,000	52,634
Vineland City Of	Howard Down	ST	FO6	11,000	52,645
PECO Energy	Falls	GT	FO2	17,000	52,665
PECO Energy	Falls	GT	FO2	17,000	52,685
PECO Energy	Falls	GT	FO2	17,000	52,705
Vineland City Of	Howard Down	ST	FO6	8,000	52,713
Public Service Electric & Gas Co.	Sewaren	ST	GAS	104,000	52,820
Pennsylvania Power & Light Co.	Fishback	GT	FO2	14,000	52,838
Pennsylvania Power & Light Co.	Fishback	GT	FO2	14,000	52,856
Delmarva Power / Conectiv	Tasley	GT	NG	26,000	52,889
Delmarva Power / Conectiv	Edge Moor	GT	NG	13,000	52,904
Delmarva Power / Conectiv	West Substation	GT	NG	15,000	52,923
PECO Energy	Richmond	GT	FO2	48,000	52,989
PECO Energy	Richmond	GT	FO2	48,000	53,055
PECO Energy	Croydon	GT	FO2	49,000	53,119
PECO Energy	Croydon	GT	FO2	49,000	53,183
PECO Energy	Croydon	GT	FO2	45,000	53,242
PECO Energy	Croydon	GT	FO2	49,000	53,306
PECO Energy	Croydon	GT	FO2	45,000	53,365
PECO Energy	Croydon	GT	FO2	49,000	53,429
PECO Energy	Croydon	GT	FO2	45,000	53,488
PECO Energy	Croydon	GT	FO2	49,000	53,552

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10⁶ Btu coal -- $5.00/10⁶ Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
PECO Energy	Moser	GT	FO2	17,000	53,572
PECO Energy	Moser	GT	FO2	17,000	53,592
PECO Energy	Moser	GT	FO2	17,000	53,612
Pennsylvania Power & Light Co.	Jenkins	GT	FO2	14,000	53,630
Pennsylvania Power & Light Co.	Jenkins	GT	FO2	14,000	53,648
Baltimore Gas & Electric Co	Gould Street	ST	OIL	104,000	53,752
Potomac Electric Power Co.	Morgantown	GT	FO2	16,000	53,772
PECO Energy	Schuylkill	ST	OIL	166,000	53,947
Pennsylvania Power & Light Co.	Allentown	GT	FO2	14,000	53,965
Pennsylvania Power & Light Co.	Allentown	GT	FO2	14,000	53,983
Pennsylvania Power & Light Co.	Allentown	GT	FO2	14,000	54,001
Pennsylvania Power & Light Co.	Allentown	GT	FO2	14,000	54,019
PECO Energy	Eddystone	GT	FO2	17,000	54,039
PECO Energy	Chester	GT	FO2	13,000	54,057
PECO Energy	Chester	GT	FO2	13,000	54,075
PECO Energy	Chester	GT	FO2	13,000	54,093
Sunbury Generation, L. L. C.	Sunbury	GT	FO1	18,000	54,117
Sunbury Generation, L. L. C.	Sunbury	GT	FO1	18,000	54,141
Sithe Power Marketing, L. P.	Werner	GT	OIL	53,000	54,214
Easton Utilities Comm.	Easton 7	IC	FO2	1,500	54,215
Sunbury Generation, L. L. C.	Sunbury	IC	FO1	3,000	54,218
Sunbury Generation, L. L. C.	Sunbury	IC	FO1	3,000	54,221
Atlantic Electric / Conectiv	B L England	IC	FO2	2,000	54,223
Pennsylvania Power & Light Co.	Amity Landfill	IC	FO2	1,000	54,224
Pennsylvania Power & Light Co.	Brunner Island	IC	FO2	2,750	54,227
PECO Energy	Schuylkill	IC	FO2	2,800	54,230
Sithe Power Marketing, L. P.	Shawville	IC	FO1	2,000	54,232
Sithe Power Marketing, L. P.	Shawville	IC	FO1	2,000	54,234
Easton Utilities Comm.	Easton	IC	FO2	5,600	54,239
Atlantic Electric / Conectiv	B L England	IC	FO2	2,000	54,241
Atlantic Electric / Conectiv	B L England	IC	FO2	2,000	54,243
Atlantic Electric / Conectiv	B L England	IC	FO2	2,000	54,245
Sithe Power Marketing, L. P.	Shawville	IC	FO1	2,000	54,247
Easton Utilities Comm.	Easton 6	IC	FO2	1,500	54,249
Easton Utilities Comm.	Easton	IC	FO2	2,000	54,251
Easton Utilities Comm.	Easton	IC	FO2	5,600	54,256
Easton Utilities Comm.	Easton	IC	FO2	4,100	54,261
Easton Utilities Comm.	Easton	IC	FO2	3,600	54,264
Easton Utilities Comm.	Easton	IC	FO2	3,500	54,268
Easton Utilities Comm.	Easton	IC	FO2	2,500	54,270
Easton Utilities Comm.	Easton	IC	FO2	2,000	54,272
Easton Utilities Comm.	Easton	IC	FO2	2,000	54,274

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

Baseline $1.35/10^6$ Btu coal -- $5.00/10^6$ Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
PECO Energy	Cromby	IC	FO2	2,700	54,277
Public Service Electric & Gas Co.	TDEC	IC	FO2	12,000	54,289
Public Service Electric & Gas Co.	Kinsley	IC	FO2	2,500	54,291
Pennsylvania Power & Light Co.	Brunner Island	IC	FO2	2,750	54,294
Easton Utilities Comm.	Easton	IC	FO2	2,000	54,296
Easton Utilities Comm.	Easton 2	IC	FO2	6,250	54,302
Easton Utilities Comm.	Easton 3	IC	FO2	6,250	54,309
Easton Utilities Comm.	Easton 4	IC	FO2	6,300	54,315
Easton Utilities Comm.	Easton 5	IC	FO2	6,300	54,321
PECO Energy	Delaware	IC	FO2	2,700	54,324
Pennsylvania Power & Light Co.	Brunner Island	IC	FO2	2,700	54,327
Pennsylvania Power & Light Co.	Harrisburg	GT	FO2	14,000	54,345
Pennsylvania Power & Light Co.	Harrisburg	GT	FO2	14,000	54,363
Pennsylvania Power & Light Co.	Harrisburg	GT	FO2	14,000	54,381
Pennsylvania Power & Light Co.	Harrisburg	GT	FO2	14,000	54,399
Baltimore Gas & Electric Co	Westport		OIL		54,399
Atlantic Electric / Conectiv	Middle	GT	KER	20,000	54,422
Atlantic Electric / Conectiv	Middle	GT	KER	20,000	54,445
Baltimore Gas & Electric Co	Riverside	GT	FO2	22,000	54,470
Public Service Electric & Gas Co.	National Park	GT	KER	21,000	54,494
Delmarva Power / Conectiv	Indian River	GT	FO2	17,000	54,515
Baltimore Gas & Electric Co	Riverside	GT	FO2	22,000	54,540
Public Service Electric & Gas Co.	Sewaren	GT	KER	129,000	54,680
Pennsylvania Power & Light Co.	Williamsport	GT	FO2	14,000	54,698
PECO Energy	Delaware	GT	FO2	17,000	54,718
Atlantic Electric / Conectiv	Carlls Corner	GT	NG	37,000	54,761
Atlantic Electric / Conectiv	Carlls Corner	GT	NG	36,000	54,804
Public Service Electric & Gas Co.	Kearny	GT	NG	21,000	54,828
Pennsylvania Power & Light Co.	Lock Haven	GT	FO2	14,000	54,846
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,863
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,880
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,897
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,914
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,931
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,948
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,965
Baltimore Gas & Electric Co	Notch Cliff	GT	NG	16,000	54,982
Baltimore Gas & Electric Co	Herbert A Wagner	ST	OIL	410,000	55,397
Pennsylvania Power & Light Co.	Harwood	GT	FO2	14,000	55,415
Pennsylvania Power & Light Co.	Harwood	GT	FO2	14,000	55,433
Public Service Electric & Gas Co.	Bayonne	GT	KER	21,000	55,457
Public Service Electric & Gas Co.	Bayonne	GT	KER	21,000	55,481

Exhibit 6-1. GEMSET Baseline Threshold Bid Price Ranking Order of Existing Units in the PJM Fleet (*continued*)

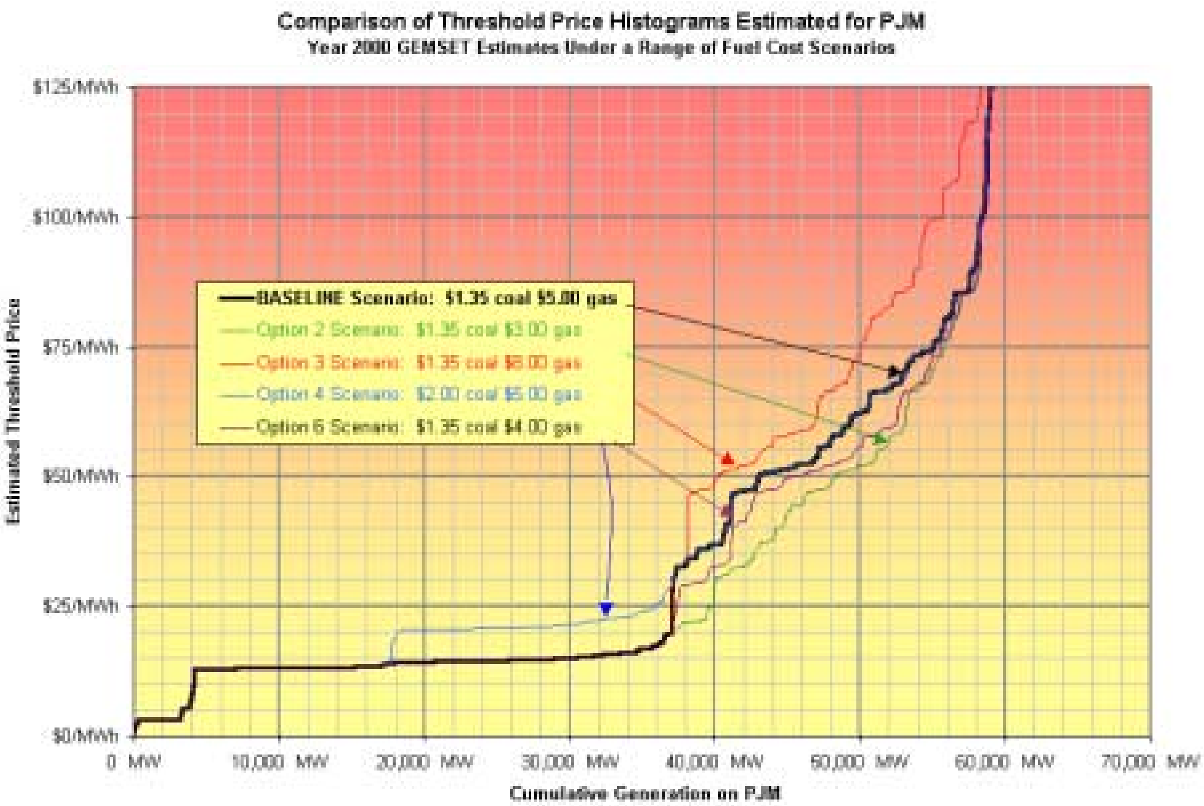
Baseline $1.35/10^6 Btu coal -- $5.00/10^6 Btu gas

Utility	Plant Name	Unit Type	Fuel	Summer kW	Cumulative MW
Baltimore Gas & Electric Co	C P Crane	GT	FO2	14,000	55,498
PECO Energy	Delaware	ST	OIL	124,000	55,626
PECO Energy	Eddystone	ST	OIL	279,000	55,914
Delmarva Power / Conectiv	Christiana	GT	FO2	22,500	55,939
Delmarva Power / Conectiv	Christiana	GT	FO2	22,500	55,964
Baltimore Gas & Electric Co	Westport	GT	NG	121,000	56,096
Dover City Of	McKee Run	ST	OIL	17,000	56,113
Public Service Electric & Gas Co.	Linden	ST	OIL	174,000	56,293
Delmarva Power / Conectiv	Delaware City	GT	FO2	16,000	56,311
Atlantic Electric / Conectiv	Cedar	GT	KER	46,000	56,363
Baltimore Gas & Electric Co	Philadelphia Road	GT	FO2	16,000	56,380
Baltimore Gas & Electric Co	Philadelphia Road	GT	FO2	16,000	56,397
Baltimore Gas & Electric Co	Philadelphia Road	GT	FO2	16,000	56,414
Baltimore Gas & Electric Co	Philadelphia Road	GT	FO2	16,000	56,431
Atlantic Electric / Conectiv	Missouri Avenue	GT	KER	20,000	56,455
Atlantic Electric / Conectiv	Missouri Avenue	GT	KER	20,000	56,479
Atlantic Electric / Conectiv	Missouri Avenue	GT	KER	20,000	56,503
Public Service Electric & Gas Co.	Linden	ST	OIL	250,000	56,753
Baltimore Gas & Electric Co	Herbert A Wagner	GT	FO2	14,000	56,770
Public Service Electric & Gas Co.	Hudson	GT	KER	129,000	56,910
Potomac Electric Power Co.	Benning	ST	OIL	275,000	57,185
Potomac Electric Power Co.	Buzzard Point	GT	FO2	128,000	57,345
Potomac Electric Power Co.	Buzzard Point	GT	FO2	128,000	57,505
PECO Energy	Eddystone	ST	OIL	380,000	57,885
Public Service Electric & Gas Co.	Mercer	GT	KER	129,000	58,025
Public Service Electric & Gas Co.	Kearny	ST	OIL	150,000	58,175
Baltimore Gas & Electric Co	Riverside	GT	NG	129,000	58,308
Delmarva Power / Conectiv	Madison Street	GT	FO2	11,000	58,322
Public Service Electric & Gas Co.	Salem	GT	FO2	38,000	58,368
PECO Energy	Schuylkill	GT	FO2	17,000	58,388
PECO Energy	Schuylkill	GT	FO2	13,000	58,406
Public Service Electric & Gas Co.	Kearny	ST	OIL	150,000	58,556
Potomac Electric Power Co.	Benning	ST	OIL	275,000	58,831
Atlantic Electric / Conectiv	Deepwater	ST	FO6	-	58,831
Public Service Electric & Gas Co.	Burlington	CT	OIL	184,000	59,026
Dover City Of	McKee Run	ST	OIL	102,000	59,128

7. PJM Threshold Bid Price and Price Projections Under the Different Study Scenarios

The estimated production units in PJM are evaluated under the several scenarios of fuel price. In each scenario, every unit in PJM is re-stacked according to their expect threshold bid price under that particular scenario. This results in the estimated threshold bid price histograms for each scenario shown as Exhibit 7-1.

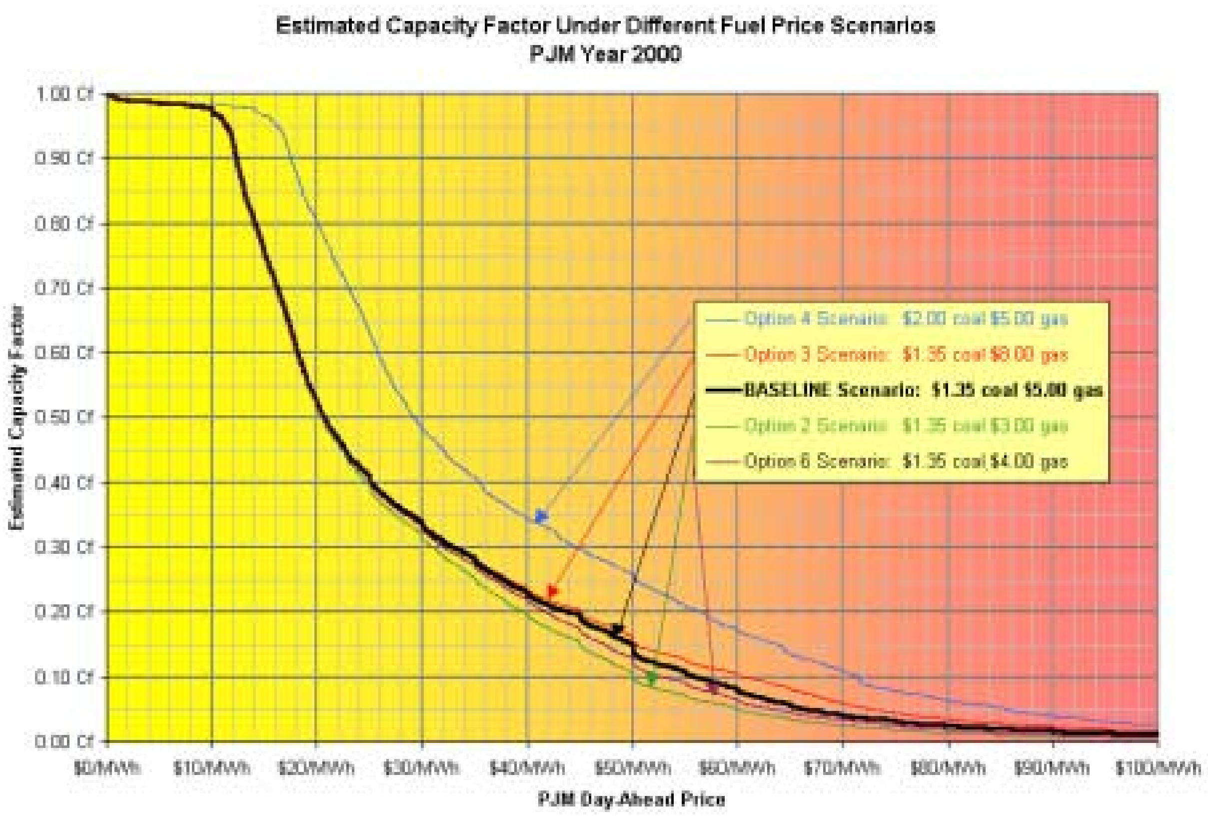
Exhibit 7-1
Threshold Bid Price Estimated for Each of the Study Fuel Cost Scenarios



The Exhibit 7-1 estimates of threshold bid prices under the several scenarios of fuel price in PJM were then mapped against hour-by-hour demand for each scenario. This presumed that differences in electric price in each case were not large enough to substantially alter demand in the region. Competitive electric bid price variability versus threshold bid price was assumed to be about the same under each scenario. From this, estimated day-ahead price was mapped. This results in the estimated day-ahead price histograms for each scenario shown as Exhibit 7-2. These

Exhibit 7-2 curves provide the capacity factor information used in the economic studies discussed next in Sections 9 through 14 for the five scenarios.

Exhibit 7-2
Estimated PJM Day-Ahead Price for Each of the Study Fuel Cost Scenarios



8. Overview of Results of the Several Scenarios

This section summarizes the results of each scenario. It gives comparison tables of the results that are described and discussed in detail for each of the scenarios in Sections 0 through 14.

Exhibits Exhibit 8-1 through Exhibit 8-3 tabulate summaries of the several scenarios for the simple cycle gas turbine, combined cycle, and pulverized coal plants of various sizes.

Exhibit 8-1 Summary of Simple Cycle Gas Turbine Scenario Results

Unit Size MW	Plant Cost	SSGT: Heat Rate	Threshold Bid Price	Capacity Factor)	Output	Break-Even COE Needed	Expected Revenue
Scenario 2: $1.35/10^6 Btu coal $3.00/10^6 Btu gas							
50 MW	$ 327 /kW	10,611 Btu/kWh	$32.13/MWh	0.290 Cf	127,037 MWh	$51.36/MWh	$49.99/MWh
100 MW	$ 281 /kW	10,053 Btu/kWh	$30.46/MWh	0.310 Cf	271,226 MWh	$46.50/MWh	$48.80/MWh
150 MW	$ 257 /kW	9,740 Btu/kWh	$29.52/MWh	0.330 Cf	433,762 MWh	$43.60/MWh	$47.63/MWh
200 MW	$ 241 /kW	9,524 Btu/kWh	$28.87/MWh	0.340 Cf	595,700 MWh	$41.93/MWh	$47.08/MWh
250 MW	$ 229 /kW	9,359 Btu/kWh	$28.38/MWh	0.349 Cf	765,316 MWh	$40.65/MWh	$46.57/MWh
Scenario 6: $1.35/10^6 Btu coal $4.00/10^6 Btu gas							
50 MW	$ 327 /kW	10,611 Btu/kWh	$42.75/MWh	0.200 Cf	87,600 MWh	$70.63/MWh	$60.30/MWh
100 MW	$ 281 /kW	10,053 Btu/kWh	$40.51/MWh	0.220 Cf	192,750 MWh	$63.08/MWh	$58.55/MWh
150 MW	$ 257 /kW	9,740 Btu/kWh	$39.26/MWh	0.240 Cf	315,450 MWh	$58.63/MWh	$56.93/MWh
200 MW	$ 241 /kW	9,524 Btu/kWh	$38.39/MWh	0.240 Cf	420,600 MWh	$56.90/MWh	$56.93/MWh
250 MW	$ 229 /kW	9,359 Btu/kWh	$37.74/MWh	0.250 Cf	547,687 MWh	$54.89/MWh	$56.15/MWh
Scenario 1: Baseline $1.35/10^6 Btu coal $5.00/10^6 Btu gas							
50 MW	$ 327 /kW	10,611 Btu/kWh	$53.36/MWh	0.120 Cf	52,600 MWh	$99.79/MWh	$73.60/MWh
100 MW	$ 281 /kW	10,053 Btu/kWh	$50.56/MWh	0.140 Cf	122,650 MWh	$86.03/MWh	$70.38/MWh
150 MW	$ 257 /kW	9,740 Btu/kWh	$49.00/MWh	0.160 Cf	210,300 MWh	$78.05/MWh	$67.79/MWh
200 MW	$ 241 /kW	9,524 Btu/kWh	$47.92/MWh	0.170 Cf	297,950 MWh	$74.04/MWh	$66.63/MWh
250 MW	$ 229 /kW	9,359 Btu/kWh	$47.10/MWh	0.180 Cf	394,375 MWh	$70.92/MWh	$65.53/MWh
Scenario 3: $1.35/10^6 Btu coal $8.00/10^6 Btu gas							
50 MW	$ 327 /kW	10,611 Btu/kWh	$85.19/MWh	0.030 Cf	13,162 MWh	$270.76/MWh	$120.61/MWh
100 MW	$ 281 /kW	10,053 Btu/kWh	$80.72/MWh	0.035 Cf	30,712 MWh	$222.36/MWh	$114.92/MWh
150 MW	$ 257 /kW	9,740 Btu/kWh	$78.22/MWh	0.040 Cf	52,650 MWh	$194.25/MWh	$110.22/MWh
200 MW	$ 241 /kW	9,524 Btu/kWh	$76.49/MWh	0.040 Cf	70,200 MWh	$187.34/MWh	$110.22/MWh
250 MW	$ 229 /kW	9,359 Btu/kWh	$75.18/MWh	0.045 Cf	98,718 MWh	$170.33/MWh	$106.30/MWh
Scenario 4: $2.00/10^6 Btu coal $5.00/10^6 Btu gas							
50 MW	$ 327 /kW	10,611 Btu/kWh	$53.36/MWh	0.190 Cf	83,262 MWh	$82.69/MWh	$72.13/MWh
100 MW	$ 281 /kW	10,053 Btu/kWh	$50.56/MWh	0.200 Cf	175,200 MWh	$75.39/MWh	$71.08/MWh
150 MW	$ 257 /kW	9,740 Btu/kWh	$49.00/MWh	0.220 Cf	289,125 MWh	$70.13/MWh	$69.11/MWh
200 MW	$ 241 /kW	9,524 Btu/kWh	$47.92/MWh	0.228 Cf	400,258 MWh	$67.36/MWh	$68.33/MWh
250 MW	$ 229 /kW	9,359 Btu/kWh	$47.10/MWh	0.240 Cf	525,750 MWh	$64.96/MWh	$67.29/MWh
Scenario 5: Baseline $1.35/10^6 Btu coal this unit's local gas price is $3.00/10^6 Btu while remainder of PJM at $5.00/10^6 Btu gas							
50 MW	$ 327 /kW	10,611 Btu/kWh	$32.13/MWh	0.310 Cf	135,613 MWh	$50.15/MWh	$54.29/MWh
100 MW	$ 281 /kW	10,053 Btu/kWh	$30.46/MWh	0.330 Cf	289,175 MWh	$45.50/MWh	$52.85/MWh
150 MW	$ 257 /kW	9,740 Btu/kWh	$29.52/MWh	0.349 Cf	459,190 MWh	$42.82/MWh	$51.57/MWh
200 MW	$ 241 /kW	9,524 Btu/kWh	$28.87/MWh	0.360 Cf	630,800 MWh	$41.21/MWh	$50.89/MWh
250 MW	$ 229 /kW	9,359 Btu/kWh	$28.38/MWh	0.360 Cf	788,500 MWh	$40.29/MWh	$50.89/MWh

Exhibit 8-2 Summary of Combined Cycle Gas Turbine Scenario Results

Unit Size MW	Plant Cost	SSGT: Heat Rate	Threshold Bid Price	Capacity Factor)	Output	Break-Even COE Needed	Expected Revenue
Scenario 2: $1.35/10^6 Btu coal $3.00/10^6 Btu gas							
100 MW	$641 /kW	7,554 Btu/kWh	$23.06/MWh	0.440 Cf	385,500 MWh	$46.34/MWh	$42.13/MWh
200 MW	$559 /kW	7,210 Btu/kWh	$22.03/MWh	0.460 Cf	806,099 MWh	$41.94/MWh	$41.27/MWh
300 MW	$515 /kW	7,016 Btu/kWh	$21.45/MWh	0.480 Cf	1,261,500 MWh	$39.34/MWh	$40.45/MWh
400 MW	$487 /kW	6,881 Btu/kWh	$21.04/MWh	0.489 Cf	1,714,706 MWh	$37.83/MWh	$40.08/MWh
500 MW	$465 /kW	6,779 Btu/kWh	$20.74/MWh	0.500 Cf	2,190,249 MWh	$36.61/MWh	$39.67/MWh
Scenario 6: $1.35/10^6 Btu coal $4.00/10^6 Btu gas							
100 MW	$641 /kW	7,554 Btu/kWh	$30.62/MWh	0.330 Cf	289,175 MWh	$61.65/MWh	$50.63/MWh
200 MW	$559 /kW	7,210 Btu/kWh	$29.24/MWh	0.349 Cf	612,253 MWh	$55.45/MWh	$49.46/MWh
300 MW	$515 /kW	7,016 Btu/kWh	$28.46/MWh	0.360 Cf	946,200 MWh	$52.32/MWh	$48.83/MWh
400 MW	$487 /kW	6,881 Btu/kWh	$27.93/MWh	0.360 Cf	1,261,600 MWh	$50.74/MWh	$48.83/MWh
500 MW	$465 /kW	6,779 Btu/kWh	$27.51/MWh	0.370 Cf	1,620,874 MWh	$48.96/MWh	$48.25/MWh
Scenario 1: Baseline $1.35/10^6 Btu coal $5.00/10^6 Btu gas							
100 MW	$641 /kW	7,554 Btu/kWh	$38.17/MWh	0.250 Cf	219,075 MWh	$79.13/MWh	$58.89/MWh
200 MW	$559 /kW	7,210 Btu/kWh	$36.45/MWh	0.270 Cf	473,050 MWh	$70.37/MWh	$57.26/MWh
300 MW	$515 /kW	7,016 Btu/kWh	$35.48/MWh	0.280 Cf	735,900 MWh	$66.16/MWh	$56.48/MWh
400 MW	$487 /kW	6,881 Btu/kWh	$34.81/MWh	0.290 Cf	1,016,300 MWh	$63.13/MWh	$55.73/MWh
500 MW	$465 /kW	6,779 Btu/kWh	$34.29/MWh	0.290 Cf	1,270,375 MWh	$61.66/MWh	$55.73/MWh
Scenario 3: $1.35/10^6 Btu coal $8.00/10^6 Btu gas							
100 MW	$641 /kW	7,554 Btu/kWh	$60.83/MWh	0.100 Cf	87,650 MWh	$163.21/MWh	$84.40/MWh
200 MW	$559 /kW	7,210 Btu/kWh	$58.08/MWh	0.120 Cf	210,400 MWh	$134.35/MWh	$80.02/MWh
300 MW	$515 /kW	7,016 Btu/kWh	$56.53/MWh	0.120 Cf	315,599 MWh	$128.06/MWh	$80.02/MWh
400 MW	$487 /kW	6,881 Btu/kWh	$55.45/MWh	0.130 Cf	455,899 MWh	$118.59/MWh	$78.08/MWh
500 MW	$465 /kW	6,779 Btu/kWh	$54.63/MWh	0.130 Cf	569,874 MWh	$115.63/MWh	$78.08/MWh
Scenario 4: $2.00/10^6 Btu coal $5.00/10^6 Btu gas							
100 MW	$641 /kW	7,554 Btu/kWh	$38.17/MWh	0.310 Cf	271,226 MWh	$71.26/MWh	$61.63/MWh
200 MW	$559 /kW	7,210 Btu/kWh	$36.45/MWh	0.340 Cf	595,700 MWh	$63.39/MWh	$59.42/MWh
300 MW	$515 /kW	7,016 Btu/kWh	$35.48/MWh	0.349 Cf	918,379 MWh	$60.06/MWh	$58.76/MWh
400 MW	$487 /kW	6,881 Btu/kWh	$34.81/MWh	0.349 Cf	1,224,505 MWh	$58.31/MWh	$58.76/MWh
500 MW	$465 /kW	6,779 Btu/kWh	$34.29/MWh	0.360 Cf	1,576,999 MWh	$56.34/MWh	$58.04/MWh
Scenario 5: Baseline $1.35/10^6 Btu coal this unit's local gas price is $3.00/10^6 Btu while remainder of PJM at $5.00/10^6 Btu gas							
100 MW	$641 /kW	7,554 Btu/kWh	$23.06/MWh	0.440 Cf	385,500 MWh	$46.34/MWh	$46.25/MWh
200 MW	$559 /kW	7,210 Btu/kWh	$22.03/MWh	0.470 Cf	823,450 MWh	$41.52/MWh	$44.73/MWh
300 MW	$515 /kW	7,016 Btu/kWh	$21.45/MWh	0.480 Cf	1,261,500 MWh	$39.34/MWh	$44.25/MWh
400 MW	$487 /kW	6,881 Btu/kWh	$21.04/MWh	0.489 Cf	1,714,706 MWh	$37.83/MWh	$43.81/MWh
500 MW	$465 /kW	6,779 Btu/kWh	$20.74/MWh	0.500 Cf	2,190,249 MWh	$36.61/MWh	$43.32/MWh

Exhibit 8-3 Summary of Pulverized Coal Unit Scenario Results

Unit Size MW	Plant Cost	SSGT: Heat Rate	Threshold Bid Price	Capacity Factor)	Output	Break-Even COE Needed	Expected Revenue
Scenario 2: $1.35/10^6$ Btu coal $3.00/10^6$ Btu gas							
400 MW	$1,100 /kW	9,934 Btu/kWh	$15.11/MWh	0.750 Cf	2,627,701 MWh	$36.42/MWh	$32.33/MWh
500 MW	$1,045 /kW	9,692 Btu/kWh	$14.78/MWh	0.770 Cf	3,372,874 MWh	$34.70/MWh	$31.88/MWh
600 MW	$993 /kW	9,456 Btu/kWh	$14.47/MWh	0.790 Cf	4,152,150 MWh	$33.10/MWh	$31.44/MWh
700 MW	$943 /kW	9,225 Btu/kWh	$14.15/MWh	0.800 Cf	4,905,600 MWh	$31.83/MWh	$31.22/MWh
800 MW	$896 /kW	9,000 Btu/kWh	$13.85/MWh	0.820 Cf	5,746,799 MWh	$30.41/MWh	$30.80/MWh
Scenario 6: $1.35/10^6$ Btu coal $4.00/10^6$ Btu gas							
400 MW	$1,100 /kW	9,934 Btu/kWh	$15.11/MWh	0.750 Cf	2,627,701 MWh	$36.42/MWh	$33.78/MWh
500 MW	$1,045 /kW	9,692 Btu/kWh	$14.78/MWh	0.770 Cf	3,372,874 MWh	$34.70/MWh	$33.29/MWh
600 MW	$993 /kW	9,456 Btu/kWh	$14.47/MWh	0.790 Cf	4,152,150 MWh	$33.10/MWh	$32.81/MWh
700 MW	$943 /kW	9,225 Btu/kWh	$14.15/MWh	0.800 Cf	4,905,600 MWh	$31.83/MWh	$32.58/MWh
800 MW	$896 /kW	9,000 Btu/kWh	$13.85/MWh	0.820 Cf	5,746,799 MWh	$30.41/MWh	$32.12/MWh
Scenario 1: Baseline $1.35/10^6$ Btu coal $5.00/10^6$ Btu gas							
400 MW	$1,100 /kW	9,934 Btu/kWh	$15.11/MWh	0.750 Cf	2,627,701 MWh	$36.42/MWh	$34.80/MWh
500 MW	$1,045 /kW	9,692 Btu/kWh	$14.78/MWh	0.770 Cf	3,372,874 MWh	$34.70/MWh	$34.28/MWh
600 MW	$993 /kW	9,456 Btu/kWh	$14.47/MWh	0.790 Cf	4,152,150 MWh	$33.10/MWh	$33.79/MWh
700 MW	$943 /kW	9,225 Btu/kWh	$14.15/MWh	0.800 Cf	4,905,600 MWh	$31.83/MWh	$33.54/MWh
800 MW	$896 /kW	9,000 Btu/kWh	$13.85/MWh	0.820 Cf	5,746,799 MWh	$30.41/MWh	$33.06/MWh
Scenario 3: $1.35/10^6$ Btu coal $8.00/10^6$ Btu gas							
400 MW	$1,100 /kW	9,934 Btu/kWh	$15.11/MWh	0.750 Cf	2,627,701 MWh	$36.42/MWh	$36.08/MWh
500 MW	$1,045 /kW	9,692 Btu/kWh	$14.78/MWh	0.770 Cf	3,372,874 MWh	$34.70/MWh	$35.53/MWh
600 MW	$993 /kW	9,456 Btu/kWh	$14.47/MWh	0.790 Cf	4,152,150 MWh	$33.10/MWh	$35.00/MWh
700 MW	$943 /kW	9,225 Btu/kWh	$14.15/MWh	0.800 Cf	4,905,600 MWh	$31.83/MWh	$34.74/MWh
800 MW	$896 /kW	9,000 Btu/kWh	$13.85/MWh	0.820 Cf	5,746,799 MWh	$30.41/MWh	$34.23/MWh
Scenario 4: $2.00/10^6$ Btu coal $5.00/10^6$ Btu gas							
400 MW	$1,100 /kW	9,934 Btu/kWh	$21.57/MWh	0.630 Cf	2,207,301 MWh	$46.94/MWh	$44.38/MWh
500 MW	$1,045 /kW	9,692 Btu/kWh	$21.08/MWh	0.650 Cf	2,846,377 MWh	$44.68/MWh	$43.67/MWh
600 MW	$993 /kW	9,456 Btu/kWh	$20.61/MWh	0.680 Cf	3,574,200 MWh	$42.26/MWh	$42.65/MWh
700 MW	$943 /kW	9,225 Btu/kWh	$20.15/MWh	0.690 Cf	4,229,928 MWh	$40.65/MWh	$42.33/MWh
800 MW	$896 /kW	9,000 Btu/kWh	$19.70/MWh	0.710 Cf	4,972,210 MWh	$38.85/MWh	$41.71/MWh
Scenario 5: Baseline $1.35/10^6$ Btu coal this unit's local gas price is $3.00/10^6$ Btu while remainder of PJM at $5.00/10^6$ Btu gas							
400 MW	$1,100 /kW	9,934 Btu/kWh	$15.11/MWh	0.750 Cf	2,627,701 MWh	$36.42/MWh	$34.80/MWh
500 MW	$1,045 /kW	9,692 Btu/kWh	$14.78/MWh	0.770 Cf	3,372,874 MWh	$34.70/MWh	$34.28/MWh
600 MW	$993 /kW	9,456 Btu/kWh	$14.47/MWh	0.790 Cf	4,152,150 MWh	$33.10/MWh	$33.79/MWh
700 MW	$943 /kW	9,225 Btu/kWh	$14.15/MWh	0.800 Cf	4,905,600 MWh	$31.83/MWh	$33.54/MWh
800 MW	$896 /kW	9,000 Btu/kWh	$13.85/MWh	0.820 Cf	5,746,799 MWh	$30.41/MWh	$33.06/MWh

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9. PJM MARKET STUDY RESULTS - Scenario 1: PJM At Present: Coal $1.35 /10^6 Btu Gas $5.00/10^6 Btu

The estimated PJM system threshold bid price vs. demand for this scenario is the "Baseline Scenario" curve shown earlier as Exhibit 7-1 on page 7-56. This resulted in the expectation of PJM system day-ahead price, as shown earlier in on Exhibit 7-2 page 7-57.

PJM as it operated during year 2000 had an average coal price of about $\$1.35/10^6$ Btu, and an average natural gas price of about $\$5.00/10^6$ Btu. This scenario uses the market evaluation assumptions and methods discussed earlier to see the prospects for the types of simple cycle and combined cycle projects that might considered in the region. Would a developer be likely to choose to develop a simple cycle gas turbine project, or combined cycle project, or coal project in the PJM region if year 2000 day-ahead electric prices and year 2000 fuel costs persist? Based on the assumption that threshold bid price determines the amount of hours that a unit might actually bid into the day-ahead market, the calculations indicate that under today's pricing and fuel cost, it would be very difficult for a generator, using natural gas to operate at sufficient hours for a reasonable return on investment.

Most of the new units being added in PJM are combined cycles. How can this be, if it appears that at today's natural gas price levels, these are risky investments? The reason so many of these types of units are now entering service is that these units were planned and under construction before the rapid rise in natural gas prices of this year. The projects were based on presumptions of lower price, and once the money is sunk, they need to enter service to recover the investment, and hopefully encounter lower gas prices or higher electric sales prices later. Many of the combined cycle projects that were planned but where the purchase is not already committed are now being deferred, or the process slowed, as evaluations are being made as to which direction natural gas prices are likely to take in the future. Those owners that secured long term (5-year) contracts of natural gas at prices below that which is prevalent today would still continue so as to take advantage of the market situation they find themselves in.

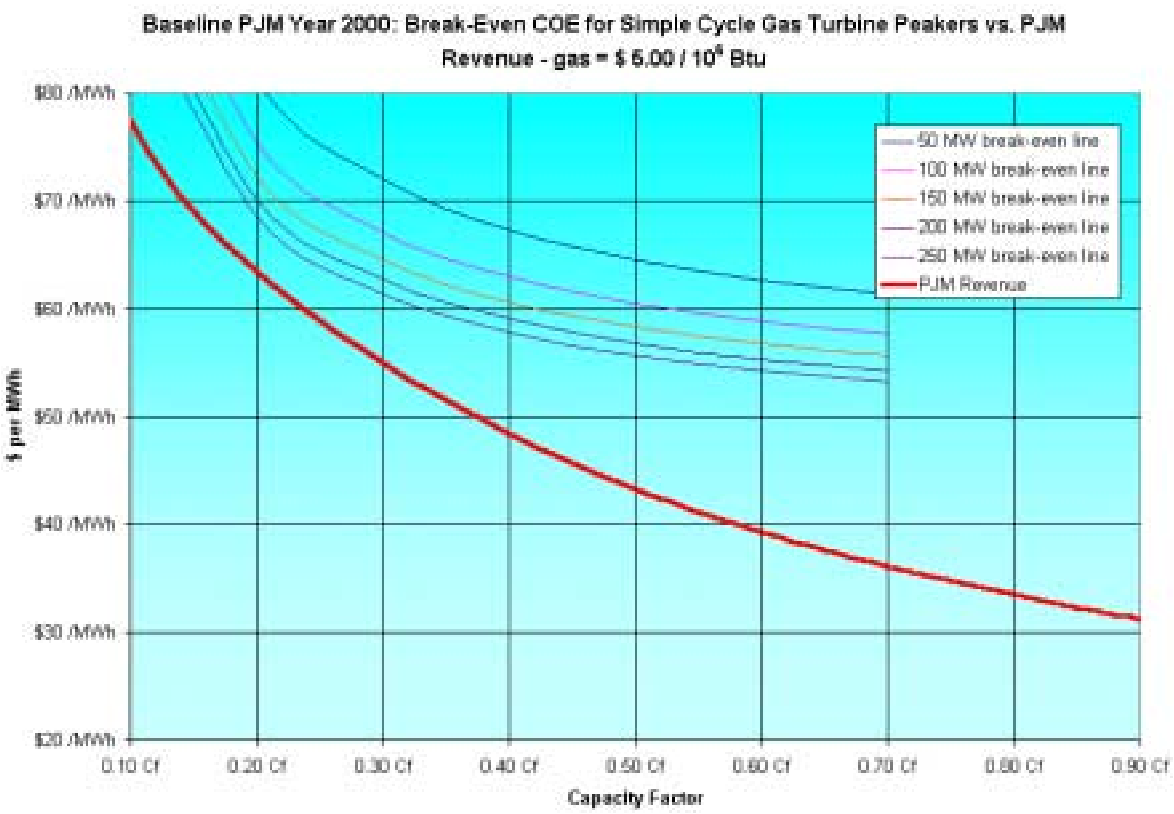
The stacking order of PJM generation for this scenario is the baseline scenario, shown earlier as **Error! Reference source not found.** on page 6-55.

9.1 Prospects for SSGT, GTCC, and Coal Projects Under Baseline Scenario 1

Baseline Scenario 1 Prospects for a Simple Cycle Gas Turbine Project. Exhibit 9-1 shows the "break-even" capacity factor needed for a simple cycle gas turbine project to pay off all debt, but make not profit. A generating company owner would have to operate at a capacity factor greater than that in the breakeven line in order to profitably repay the owner's investment. Where a capacity factor is lower than this break-even line, the generating unit would not make sufficient return to pay off debt; indicating that the unit would be losing money. The required break-even capacity factor for the simple cycle is higher than the estimated 2000 capacity factor that would result using dispatch prices above the threshold bid prices in the day-ahead market. The heavy line for PJM shows the lower level of operation that the competitive market in PJM would allow. With the year 2000 PJM day-ahead electricity price levels and $5.00/10^6 Btu gas price, a simple cycle project would not be able to return its investment.

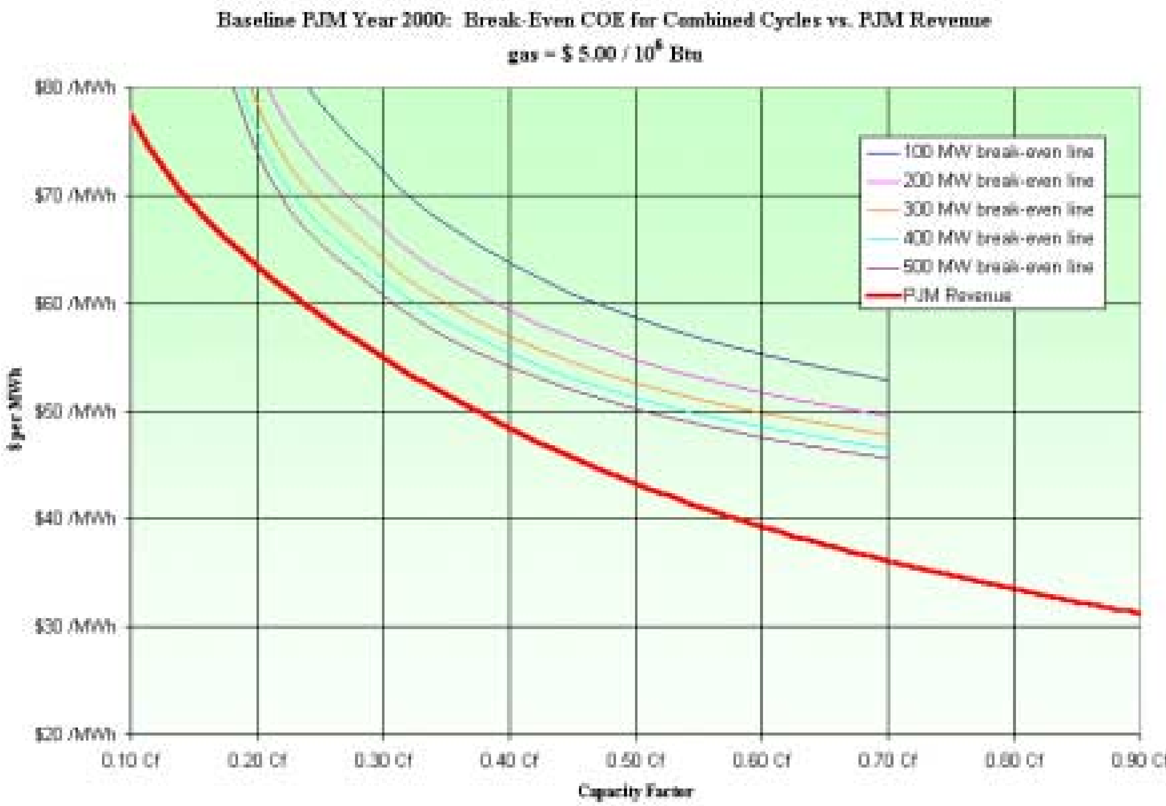
An investor would have to be confident that gas price would drop, or that PJM electricity price would rise before such a project would make investment sense.

Exhibit 9-1
Break-Even Cost of Electricity for Simple Cycle in PJM Compared to Potential Revenue



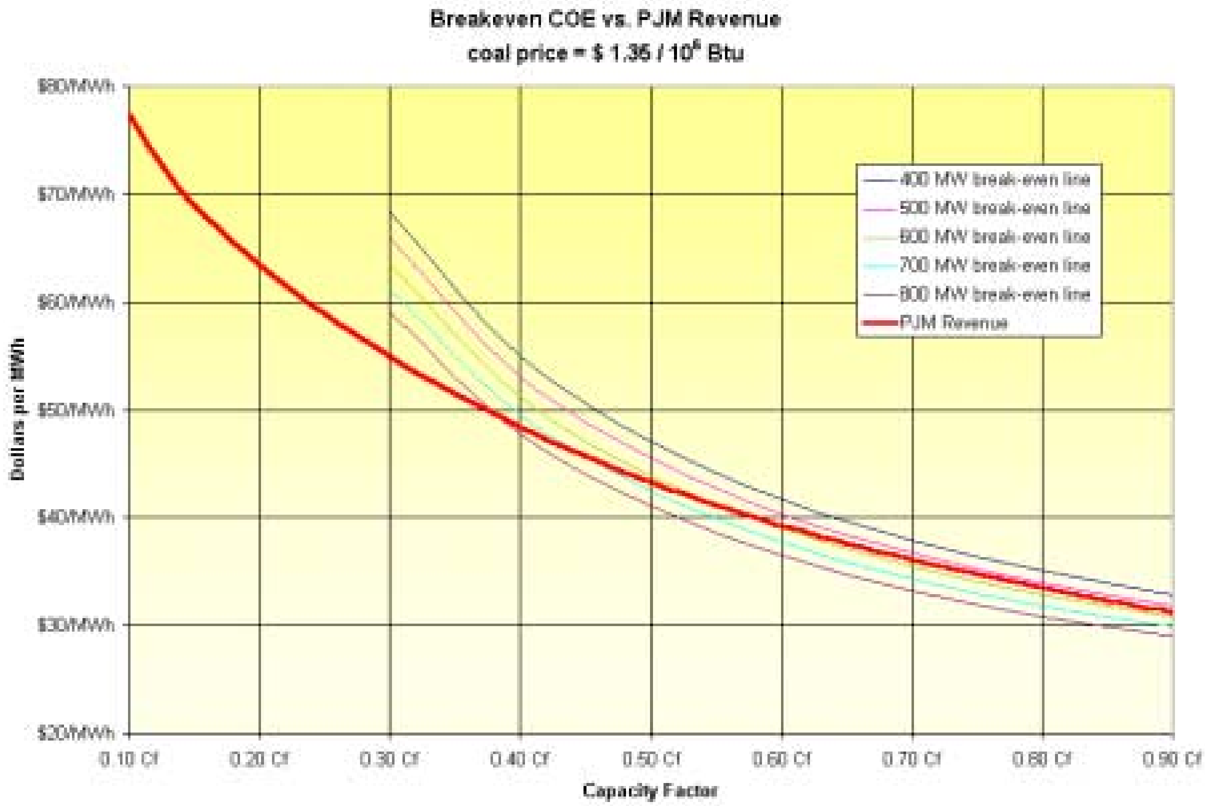
Baseline Scenario 1 Prospects for a Gas Turbine Combined Cycle Project. This type of project would not make money at $5.00 gas price, Exhibit 9-2. A potential developer would either wait for gas price to drop, or for the average price to increase above its breakeven threshold. With today's PJM day-ahead prices and today's $5.00/10^6 Btu gas price, it would be difficult for a combined cycle unit to warrant consideration unless the day-ahead market price rises substantially, or gas price drops.

Exhibit 9-2
Break-Even Cost of Electricity for Combined Cycle in PJM Compared to Potential Revenue



Baseline Scenario 1 Prospects for a Coal Plant Project. Larger coal plants would be able to make money, Exhibit 9-3. If the developer perceived that gas price would increase, or if there would be increases in demand that in future years would increase the average price, a coal project would make sense. With today's investment risk associated with coal fired units, a developer or generating company would have to hedge its investment strategy with sufficient bilateral arrangements to cover its fixed costs.

Exhibit 9-3
Break-Even Cost of Electricity for PC Coal Plant in PJM Compared to Potential Revenue



9.2 Comparison of SSGT, GTCC, and Coal Projects Under the Baseline Scenario 1

As shown in Exhibit 9-4, the natural gas type units have significantly higher threshold bid prices than coal units in today's pricing setup. This indicates much lower capacity factors if the assumed relationship between threshold bid prices and bids to the day-ahead market is valid, Exhibit 9-5. Likewise, the breakeven points for the gas units are much higher than that of the coal units with today's fuel prices and cost of capital.

Exhibit 9-4
Expected Threshold Bid Price Comparison of SSGT, GTCC, and Coal Under Baseline Scenario 1

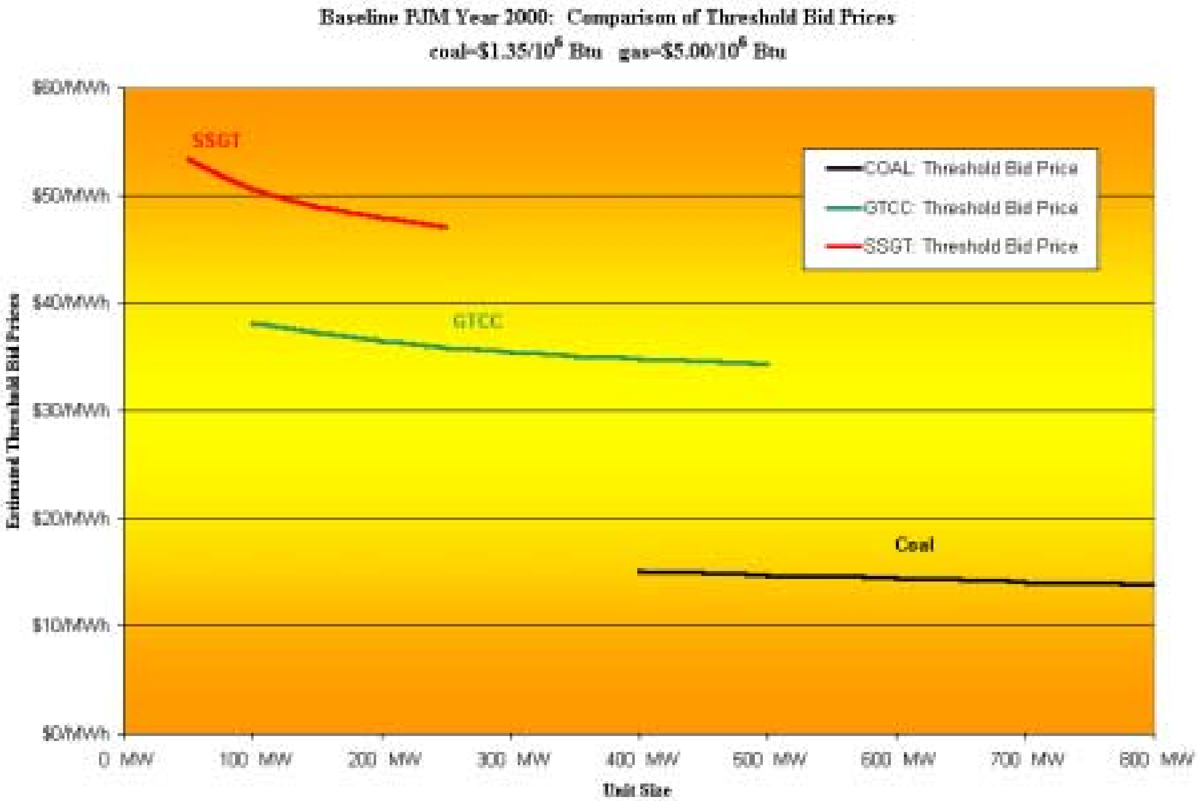
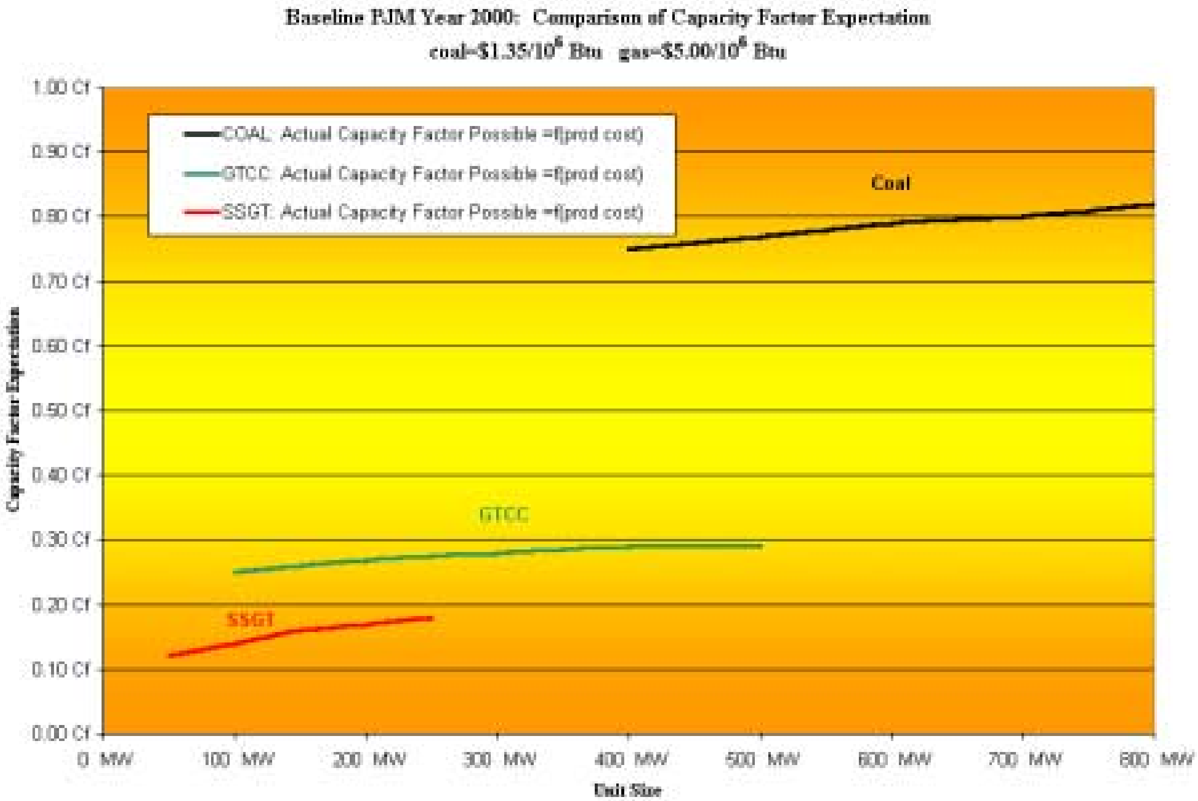
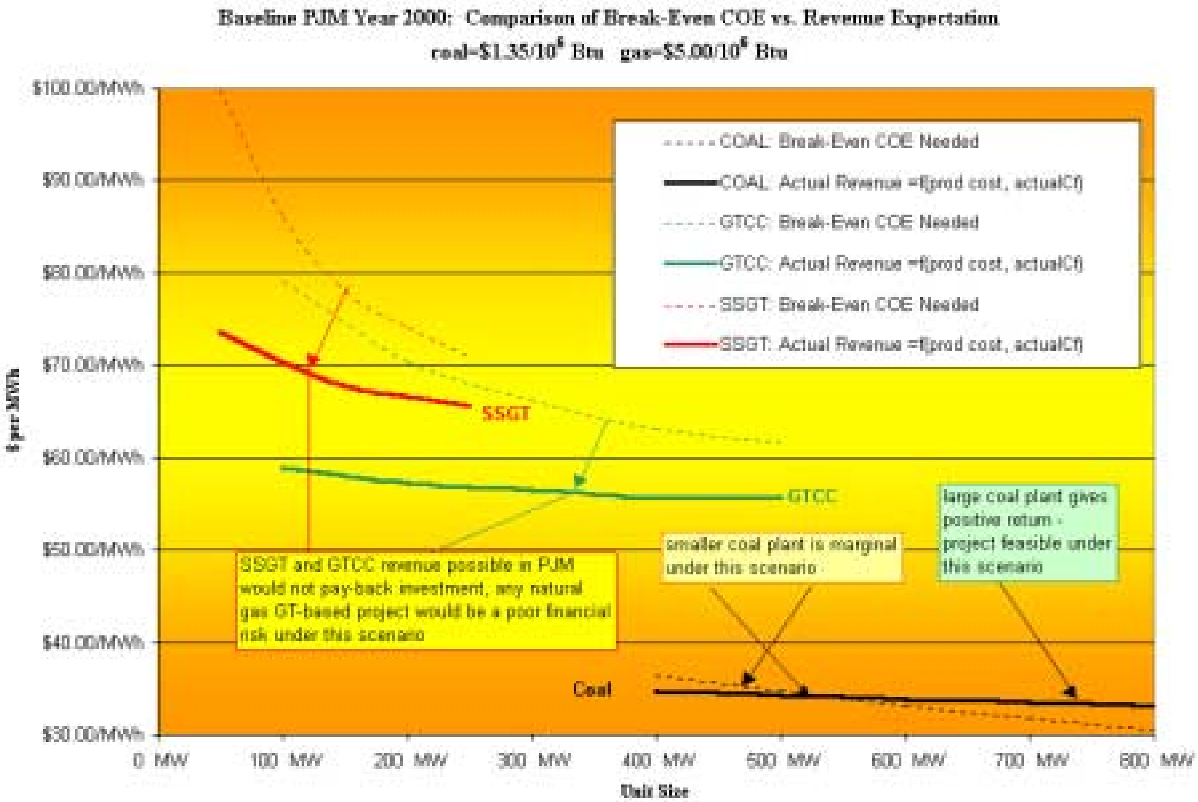


Exhibit 9-5
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under Baseline Scenario 1



For convenience, Exhibit 9-6 repeats the information shown earlier in Exhibit 3-12. This graph is a summary that compares the economic performance of the three types of generating units and their expected revenues for the year 2000, the baseline case in these studies.

Exhibit 9-6
Comparison of Baseline Scenario 1 SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2000 PJM Day-Ahead Electric Price



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10. PJM MARKET STUDY RESULTS - Scenario 2: Coal $1.35/10^6$ Btu Gas $3.00/10^6$ Btu

This scenario projects how PJM might have operated during year 2000 had the average coal price been at the baseline level of about $1.35/10^6$ Btu, and an average natural gas price of had been much lower: about $3.00/10^6$ Btu. Would a developer have been likely to choose to develop a simple cycle gas turbine project, or combined cycle project, or coal project in the PJM region under this scenario's circumstances?

The stacking order of PJM generation for this scenario changes, since the threshold bid prices of the units change, due the different fuel prices. The estimated PJM system threshold bid price vs. demand for this scenario that results from this re-stacking is the "Scenario 2" curve shown earlier as Exhibit 7-1 on page 7-56.

Based on the assumption that threshold bid prices estimated under this scenario determines the amount of hours that a unit might actually bid into the day-ahead market, PJM day-ahead electricity price can be inferred. GEMSET projections indicate that under this scenario's production pricing and fuel cost the expected S-curve histogram of this scenario's day-ahead price are as indicated in Scenario 2 in Exhibit 7-2 on page 7-57.

As shown in Exhibit 10-1, the coal units only have a marginal threshold bid price advantage at this low natural gas price level in this scenario. The lower threshold bid prices for the gas units allows them to enjoy higher capacity factors than at the higher baseline gas costs under the assumed relationship between threshold bid prices and bids to the day-ahead market, Exhibit 10-2. Any of the SSGTs would make money under this scenario, Exhibit 10-3. GTCC larger than 200 MW would make money, but smaller ones would loose. No coal project would prove profitable under this scenario.

Exhibit 10-1
Comparison of Expected Threshold Bid Prices for SSGT, GTCC, and Coal Under GEMSET Scenario 2

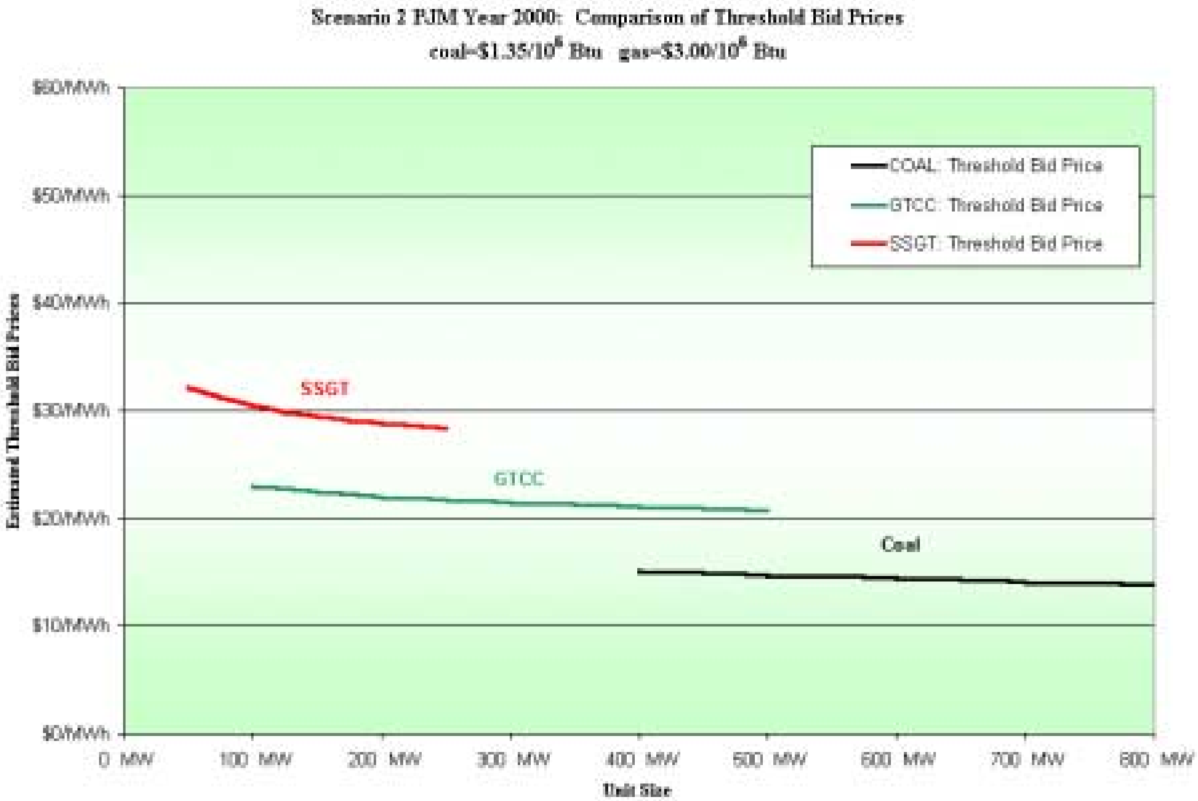


Exhibit 10-2
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under GEMSET Scenario 2

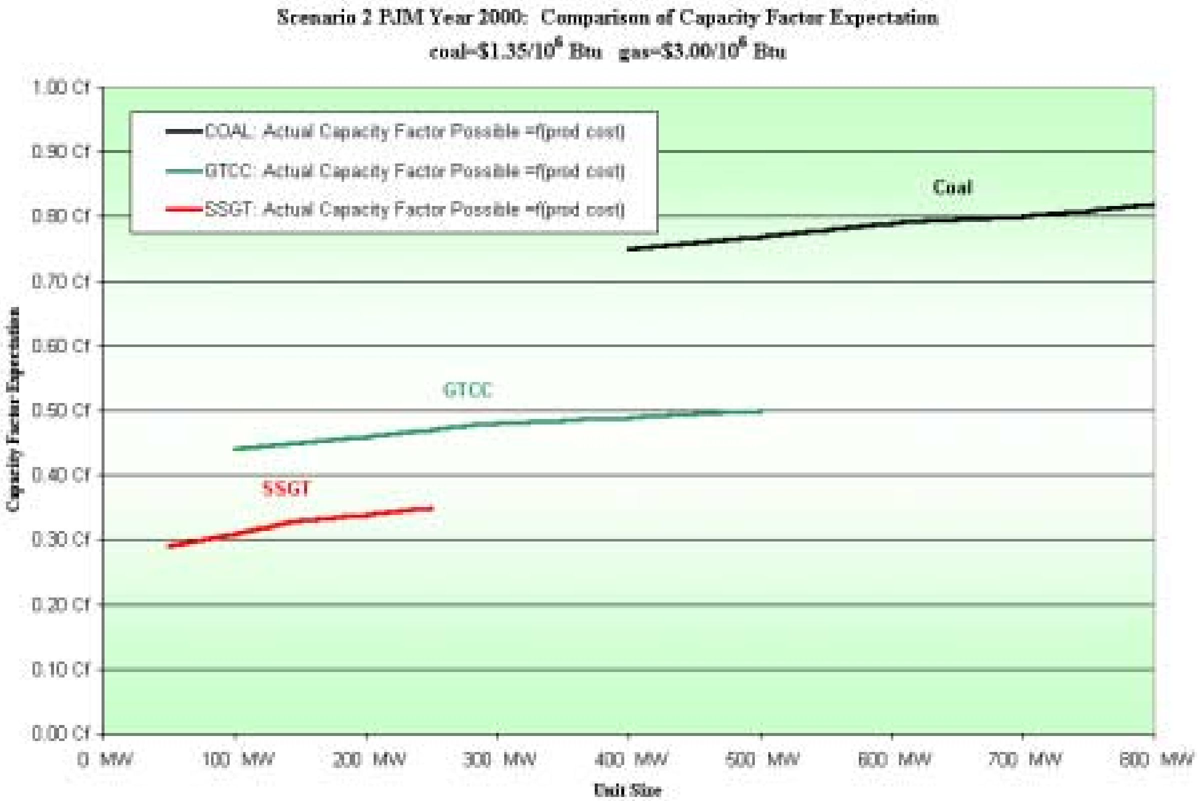
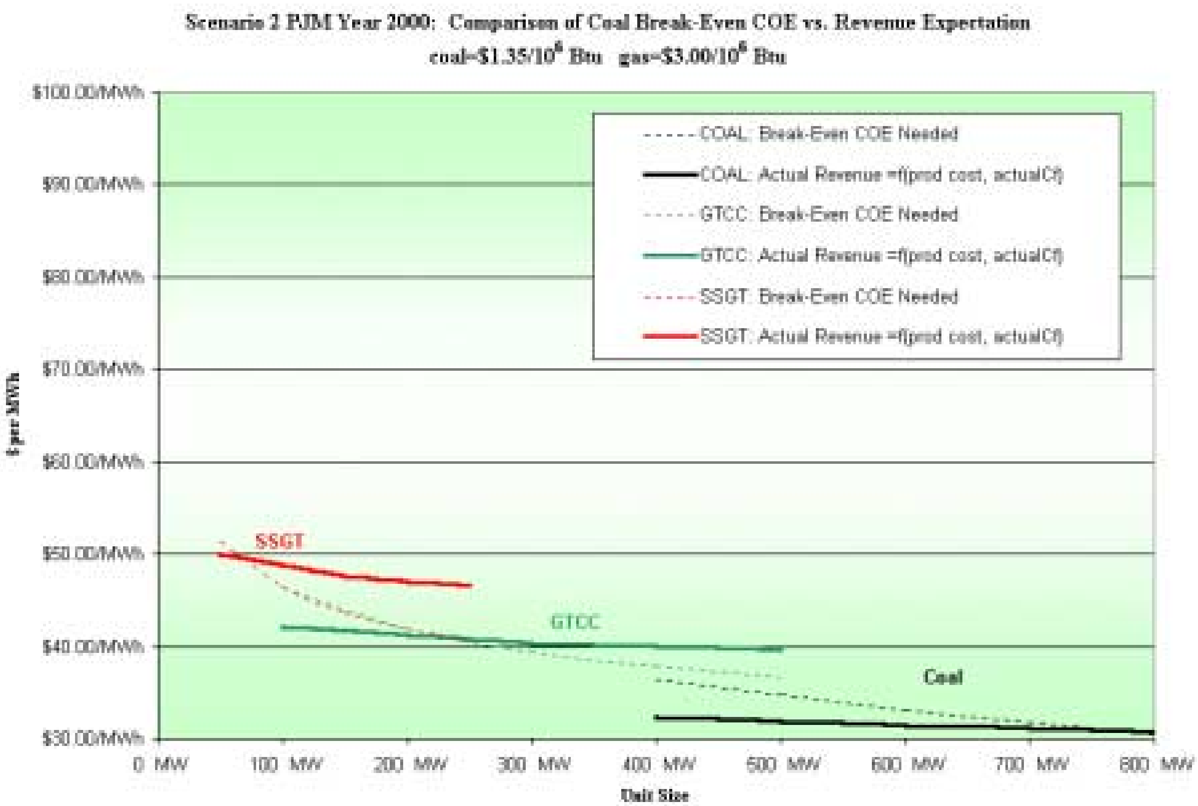


Exhibit 10-3 compares the economic performance of the three types of generating units and their expected revenues for the year 2000 under this scenario.

Exhibit 10-3
Comparison of Scenario 2 SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2000 PJM Day-Ahead Electric Price



11. PJM MARKET STUDY RESULTS - Scenario 6: Coal $1.35/10^6$ Btu Gas $4.00/10^6$ Btu

This scenario projects how PJM might have operated during year 2000 had the average coal price been at the baseline level of about $1.35/10^6$ Btu, and an average natural gas price of had been : about $4.00/10^6$ Btu. Would a developer have been likely to choose to develop a simple cycle gas turbine project, or combined cycle project, or coal project in the PJM region under this scenario's circumstances?

The stacking order of PJM generation for this scenario changes, since the threshold bid prices of the units' change, due the different fuel prices. The estimated PJM system threshold bid price vs. demand for this scenario that results from this re-stacking is the "Scenario 6" curve shown earlier as Exhibit 7-1 on page 7-56.

GEMSET projections indicate that under this scenario's production pricing and fuel cost the expected S-curve histogram of this scenario's day-ahead price are as indicated in Scenario 6 in on Exhibit 7-2 page 7-57.

As shown in Exhibit 11-1, the coal units only have a marginal threshold bid price advantage at this low natural gas price level in this scenario. The lower threshold bid prices for the gas units allows them to enjoy higher capacity factors than at the higher baseline gas costs under the assumed relationship between threshold bid prices and bids to the day-ahead market, Exhibit 11-2. Only the larger of the SSGTs would make money under this scenario, Exhibit 11-3. None of the GTCC would make money. Only the larger coal projects would prove profitable under this scenario.

Exhibit 11-1
Comparison of Expected Threshold Bid Prices for SSGT, GTCC, and Coal Under GEMSET Scenario 6

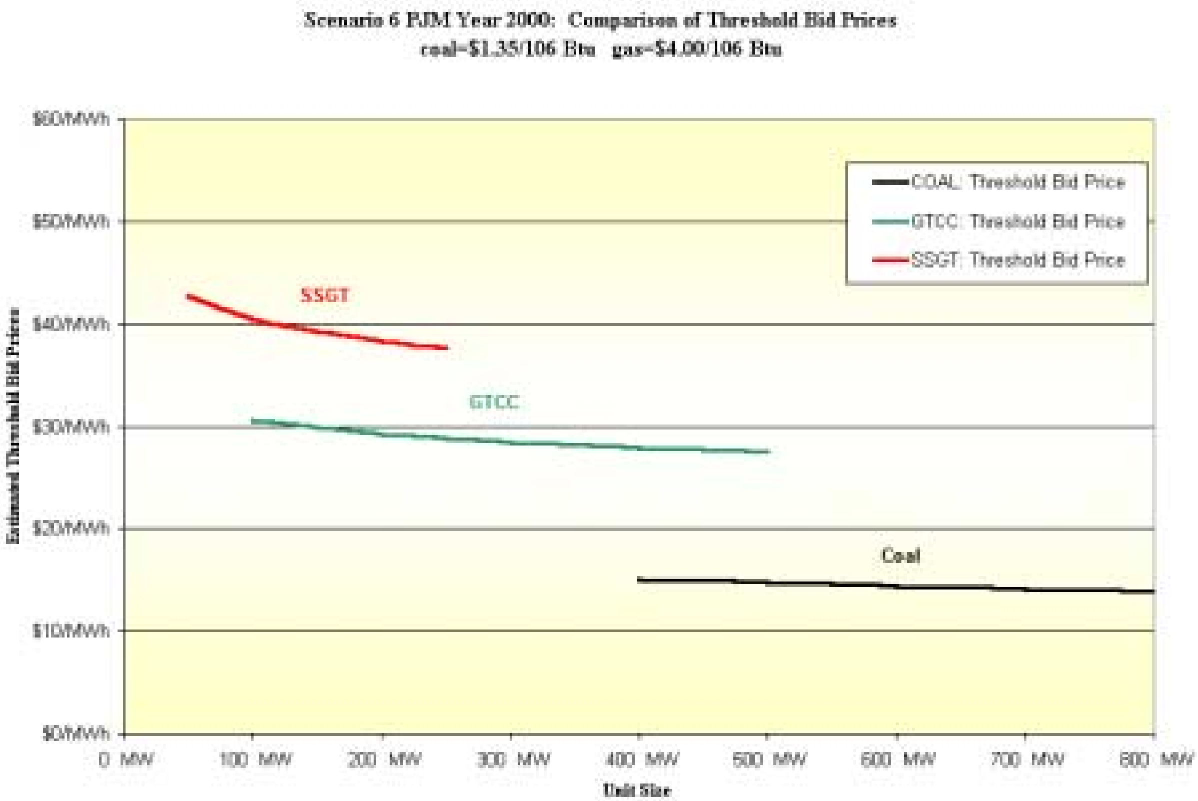


Exhibit 11-2
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under GEMSET Scenario 6

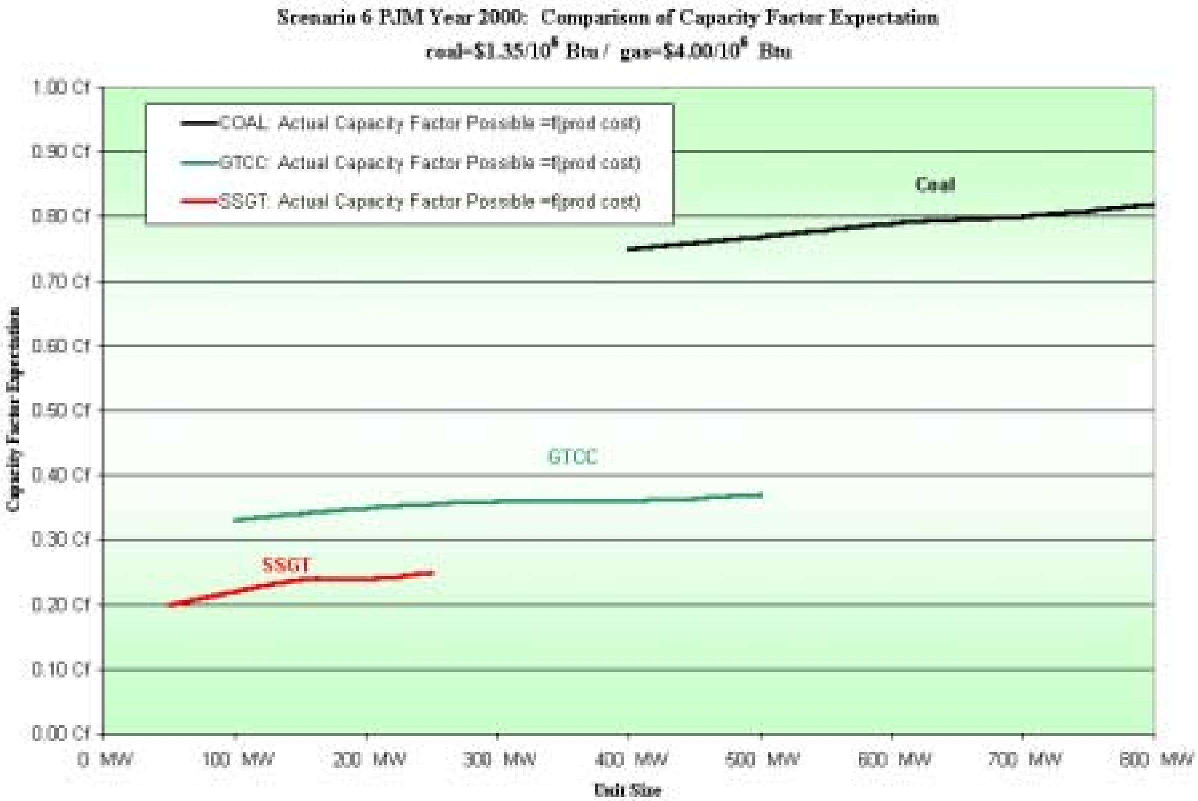
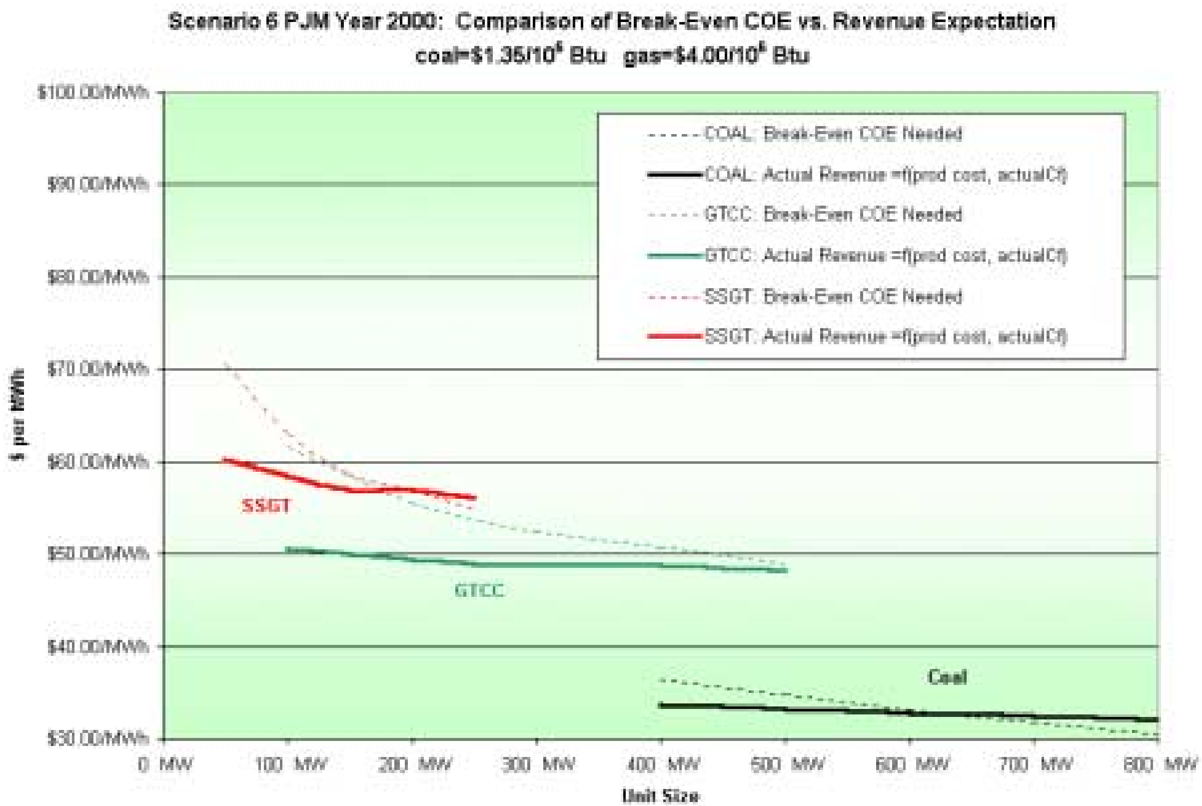


Exhibit 11-3 compares the economic performance of the three types of generating units and their expected revenues for the year 2000 under this scenario.

Exhibit 11-3
Comparison of Scenario 6 SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2000 PJM Day-Ahead Electric Price



12. PJM MARKET STUDY RESULTS - Scenario 3: Coal $1.35/10⁶ Btu Gas $8.00/10⁶ Btu

This scenario projects how PJM might have operated during year 2000 had the average coal price been at the baseline level of about $\$1.35/10^6$ Btu, and an average natural gas price of had been much higher: about $\$8.00/10^6$ Btu. Would a developer have been likely to choose to develop a simple cycle gas turbine project, or combined cycle project, or coal project in the PJM region under this scenario's circumstances?

The stacking order of PJM generation for this scenario changes, since the threshold bid prices of the units' change, due the different fuel prices. The estimated PJM system threshold bid price vs. demand for this scenario that results from this re-stacking is the "Scenario 3" curve shown earlier as Exhibit 7-1 on page 7-56.

As in previous assessments, GEMSET projections indicate that under this scenario's production pricing and fuel cost the expected S-curve histogram of this scenario's day-ahead price are as indicated in Exhibit 7-2 shown earlier on page 7-57.

As shown in Exhibit 12-1, the gas units are at a considerable threshold bid price disadvantage at the high natural gas price level in this scenario, compared to the baseline scenario. Note that the scale of this threshold bid price plot is extended compared to that for the plot of the baseline costs (shown earlier as Exhibit 9-4). The higher threshold bid prices for the gas units results in low capacity factors for thoseunits as compared against the scenario where gas prices are low.. None of the SSGTs or GTCCs would make money under this scenario, Exhibit 12-3. As in the baseline, the larger coal units would prove profitable under this scenario.

Exhibit 12-1
Expected Threshold Bid Price Comparison of SSGT, GTCC, and Coal under GEMSET Scenario 3

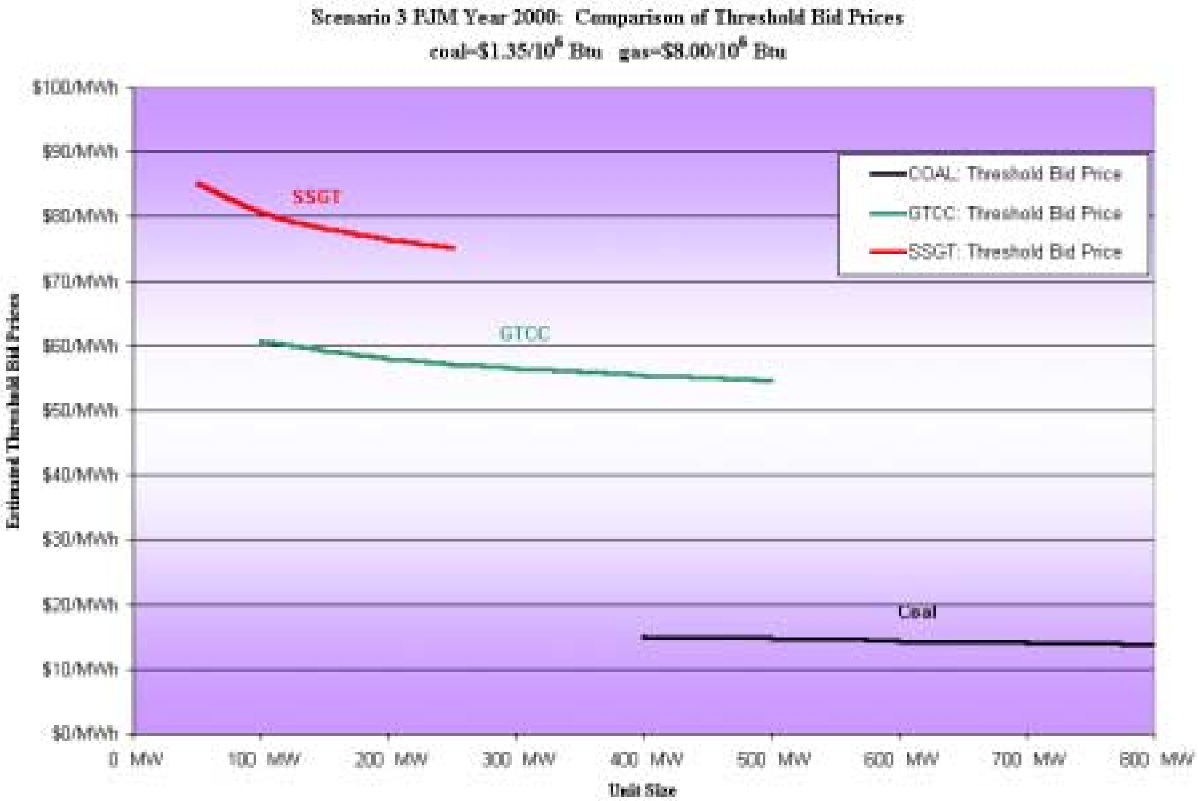


Exhibit 12-2
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under GEMSET Scenario 3

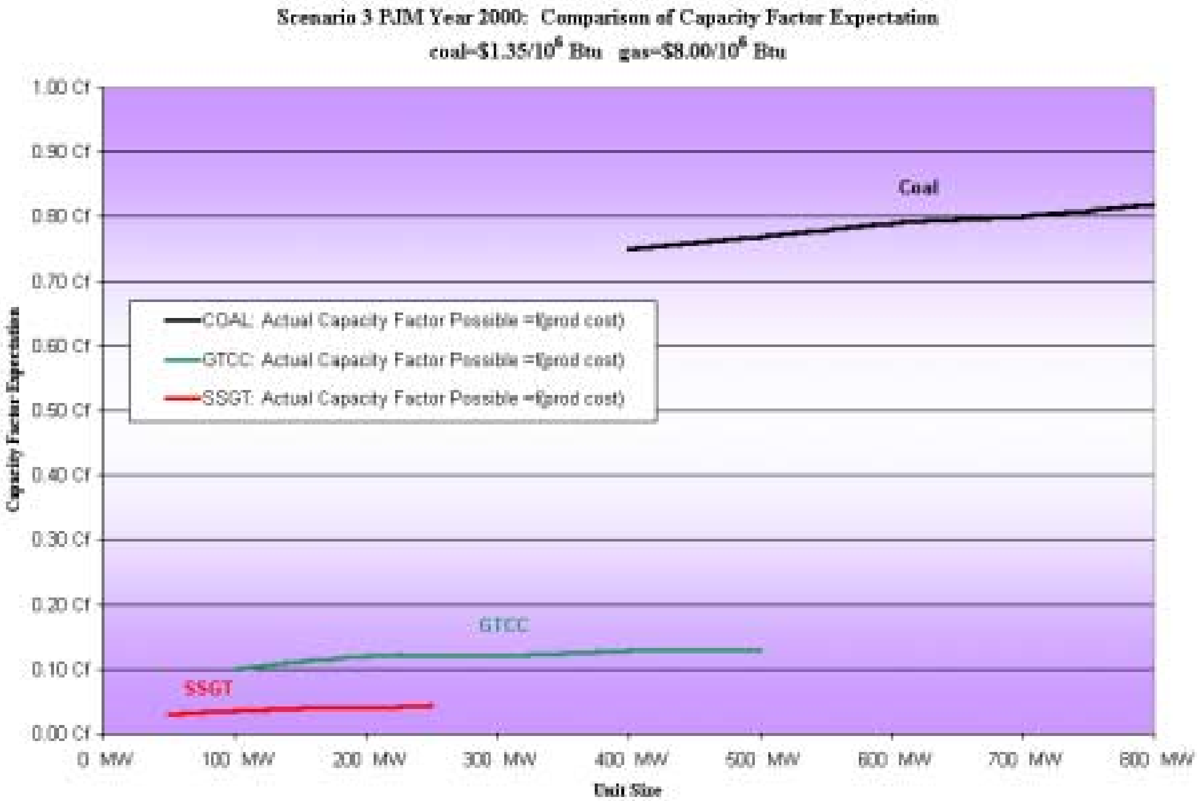
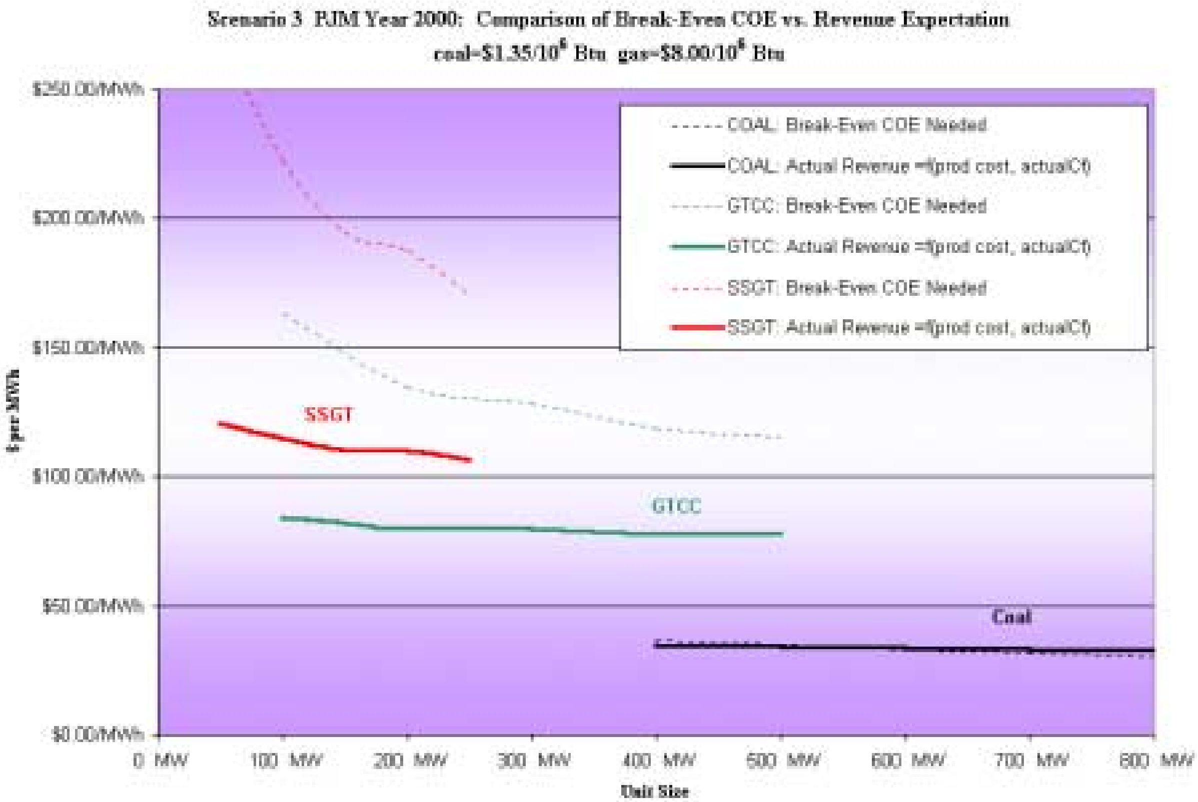


Exhibit 12-3 compares the economic performance of the three types of generating units and their expected revenues for the year 2000 under this scenario.

Exhibit 12-3
Comparison of Scenario 3 SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2000 PJM Day-Ahead Electric Price



13. PJM MARKET STUDY RESULTS - Scenario 4: Coal $2.00/10⁶ Btu Gas $5.00/10⁶ Btu

This scenario projects how PJM might have operated during year 2000 had the average coal price been above the baseline level to a level of $\$2.00/10^6$ Btu, and an average natural gas price had been at the baseline level of $\$5.00/10^6$ Btu. Would a developer have been likely to choose to develop a simple cycle gas turbine project, or combined cycle project, or coal project in the PJM region under this scenario's circumstances?

The stacking order of PJM generation for this scenario changes, since the threshold bid prices of the units change due to the different fuel prices. The estimated PJM system threshold bid price vs. demand for this scenario that results from this re-stacking is the "Scenario 4" curve shown earlier as Exhibit 7-1 on page 7-56.

GEMSET projections indicate that under this scenario's production pricing and fuel cost the expected S-curve histogram of this scenario's day-ahead price are as indicated in Scenario 4 in Exhibit 7-2, page 7-57.

As shown in Exhibit 13-1, the coal units decrease in their threshold bid price advantage over gas at the coal price level in this scenario compared to the baseline scenario. Still, "coal is king," and retains its position as the low cost producer. The higher threshold bid prices for the coal units results in a significantly lower capacity factors for the coal units and increased capacity factor for the gas units than at the lower baseline coal costs under the assumed relationship between threshold bid prices and bids to the day-ahead market, Exhibit 13-2. The larger revenue stream from increased capacity factor means that larger (above about 75MW) SSGTs the larger (above about 250MW) GTCCs, and as in the baseline, the larger (above about 550MW) coal units would make money under this scenario, Exhibit 13-3.

Exhibit 13-1
Comparison of Expected Threshold Bid Prices for SSGT, GTCC, and Coal Under GEMSET Scenario 4

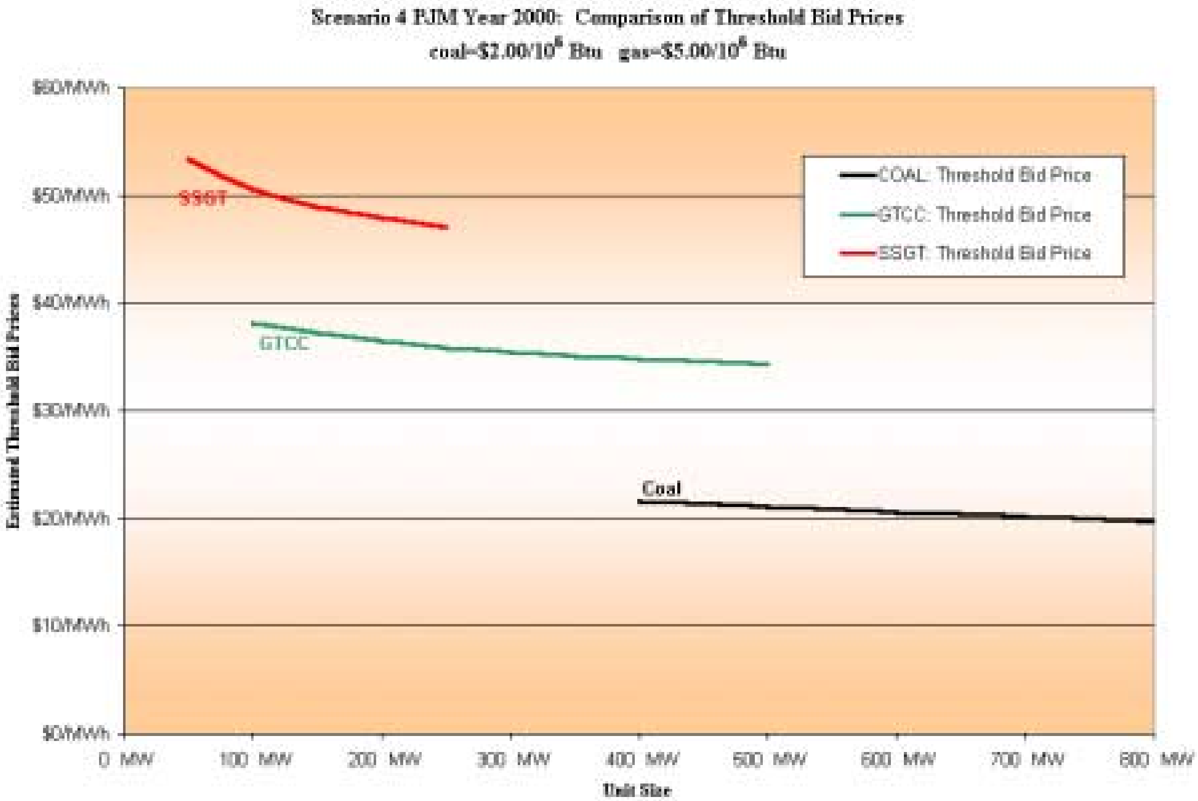


Exhibit 13-2
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under GEMSET Scenario 4

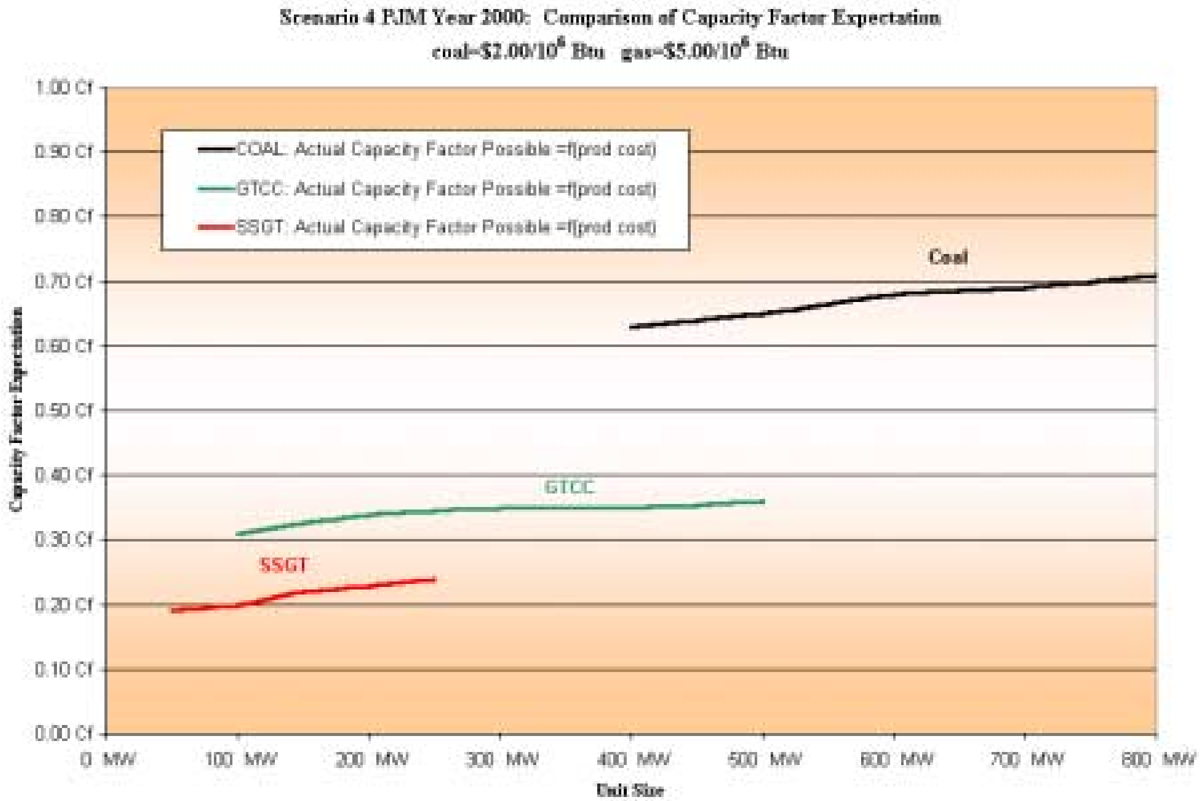
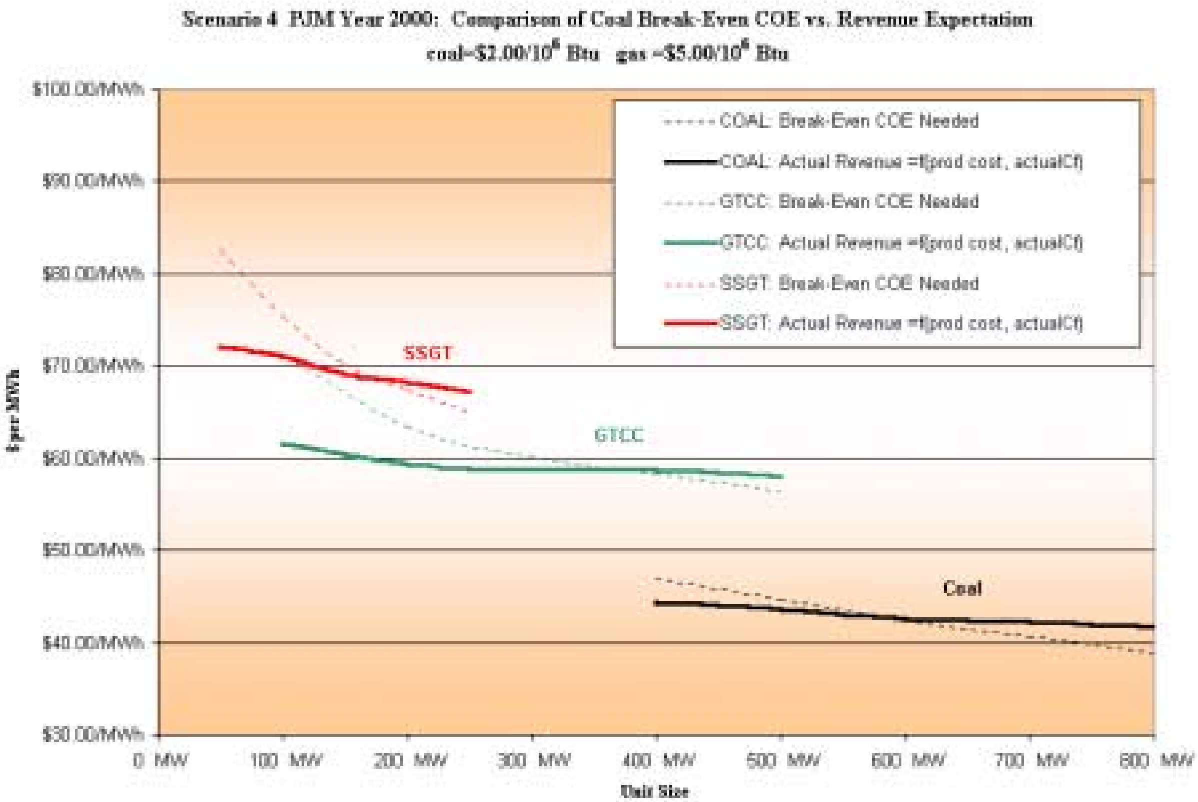


Exhibit 13-3 compares the economic performance of the three types of generating units and their expected revenues for the year 2000 under this scenario.

Exhibit 13-3
Comparison of Scenario 4 SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2000 PJM Day-Ahead Electric Price



14. PJM MARKET STUDY RESULTS - Scenario 5: PJM As Is With Coal At $1.35/10^6$ Btu and Gas $5.00/10^6$ Btu, but Local Unit Has Lower-Priced Gas $3.00/10^6$ Btu

This scenario looks at the circumstance where it is presumed that only the local unit benefits from low-price gas. All the rest of PJM's natural gas units use $5.00/10^6$ Btu gas, but the local unit benefits from lower-priced $3.00/10^6$ Btu gas. This low gas-price circumstance might exist if the owner had made prior favorable long-term fuel purchase price contract arrangements with a gas supplier.

Under this scenario, the PJM fleet price histogram and return profile are those of the existing baseline fleet (Scenario 1). The stacking order of PJM generation for this scenario is the baseline scenario, shown earlier as illustrated in Exhibit 6-1 on page 6-44. The estimated PJM system threshold bid price vs. demand for this scenario is the same as for the "Baseline Scenario" curve shown earlier as Exhibit 7-1 on page 7-56. This resulted in the expectation of PJM system day-ahead price, as shown earlier in on Exhibit 7-2 page 7-57 for the baseline scenario.

This scenario affords considerable advantage to the gas-fired local unit (existing gas-fired generators). It gets the day-ahead marginal price of the PJM system that is established under a much higher cost basis for the rest of the intermediate and peaking portion of the fleet. Coal unit COE is unaffected by gas price at this site, so it is identical to that for a coal unit evaluated in the baseline.

Exhibit 14-1
Comparison of Expected Threshold Bid Prices for SSGT, GTCC, and Coal Under GEMSET Scenario 5

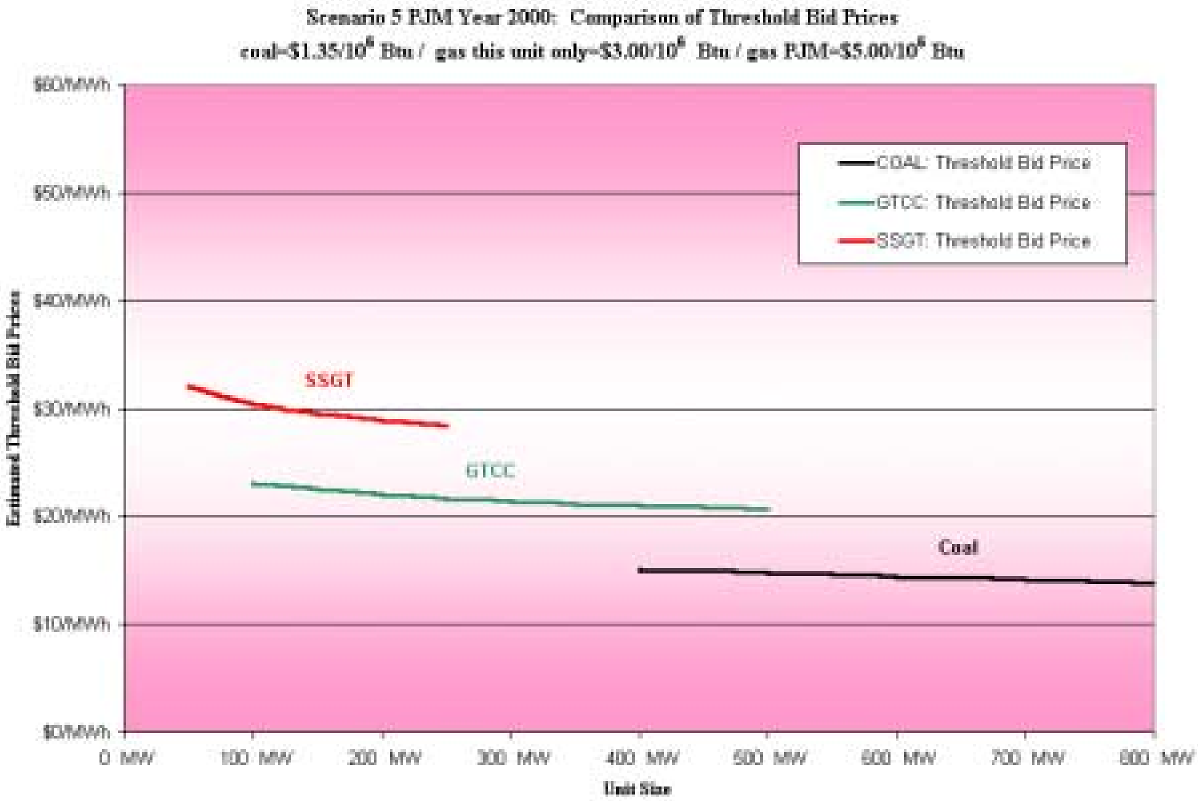


Exhibit 14-2
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under GEMSET Scenario 5

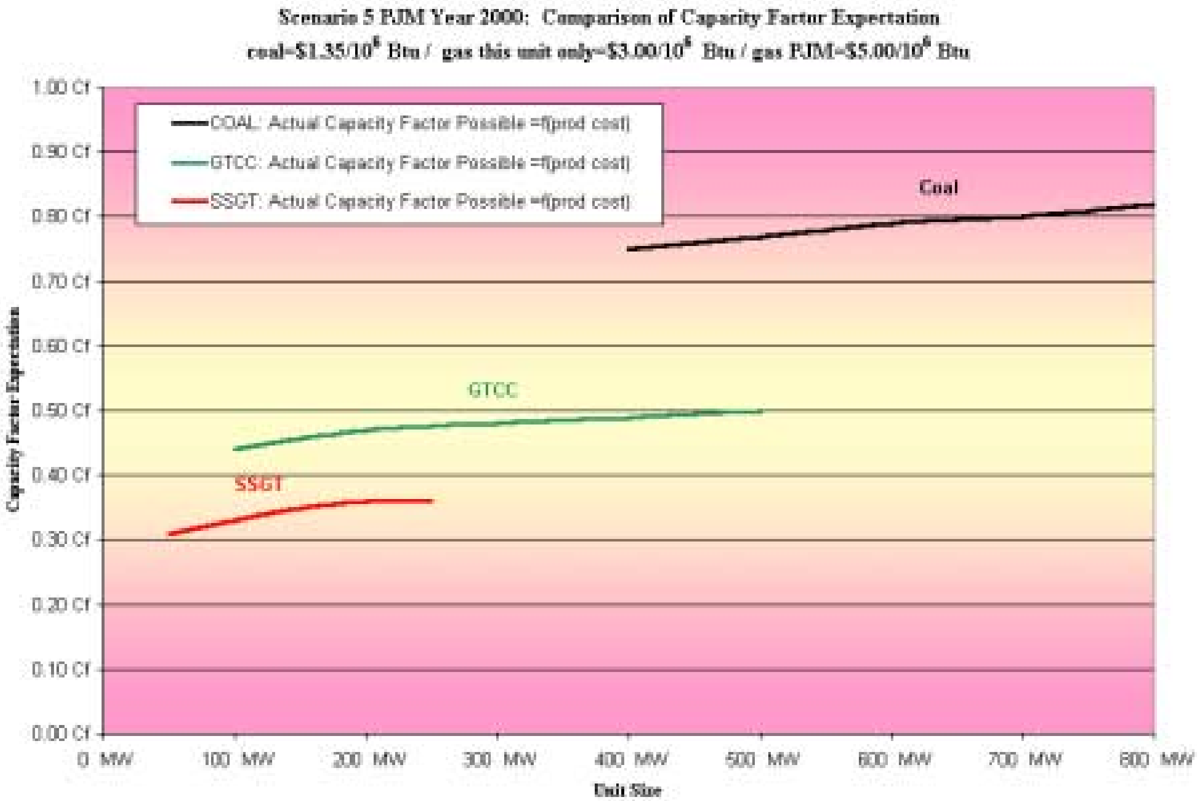
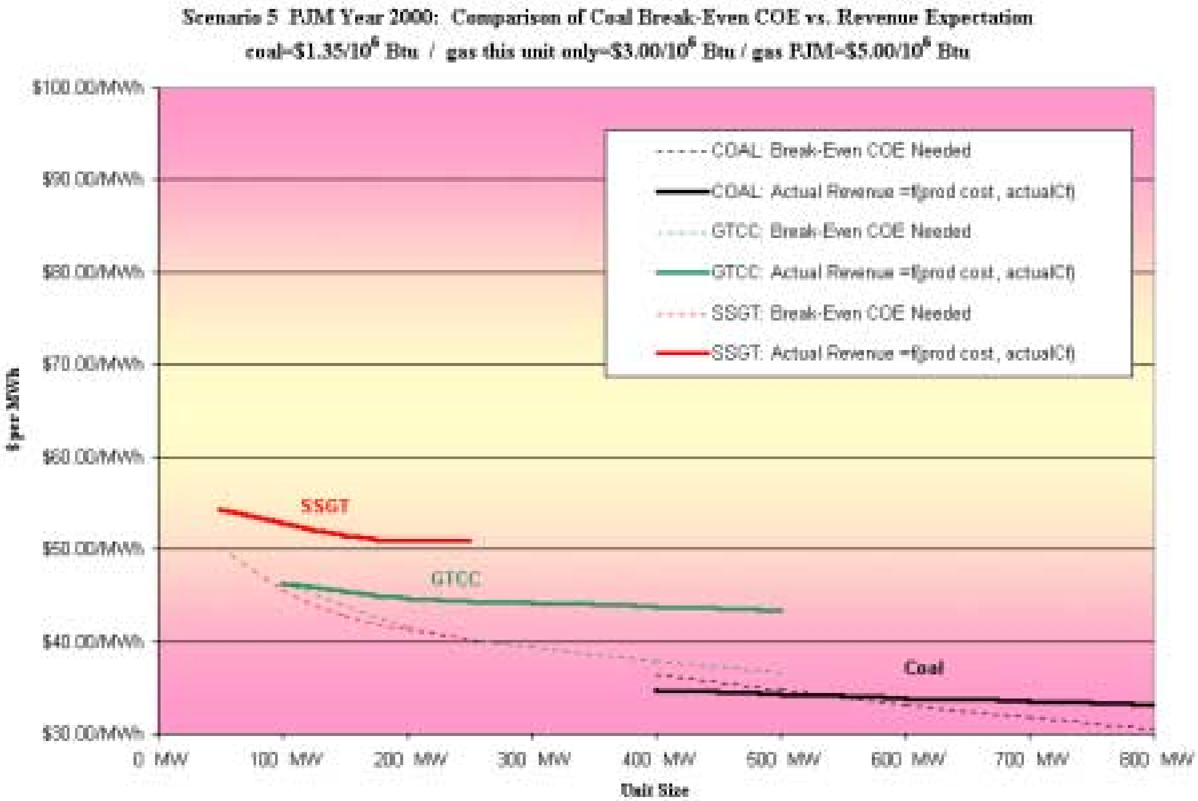


Exhibit 14-3
Comparison of Scenario 5 SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Low Local-Unit Gas Price



In the above scenario, both the simple cycle and combined cycle would generate sufficient revenues above the breakeven point previously calculated.

The cost of electricity is paramount to any analysis of this type. It must be recognized that in a competitive market, the least cost solution for adding new generation no longer exists and is replaced with a much higher risk of doing business in the market. It should also be pointed out that the free market price certainly sends out obvious signals as to what levels a unit should or must be operated in order to achieve financial robustness.

With growing demand in the PJM system, although modest in most of the in-house forecasts, the S-Curve should be moving higher as the existing units recognize that factor and bid at prices higher than those currently indicated by the historical curve. All indications are that the PJM prices will be moving higher to warrant future investment in new generating resources.

15. 5-Year Baseline Scenario Forecast of the PJM Market

All of the analysis conducted in Sections 1 through 14 were for existing conditions, that for supply and demand circumstances that exited in the baseline data for the year 2000. The scenario variations presumed operations to the same demand situation, and the analyses there for the several scenarios hypothesized differences that might be expected were fuel prices different than that of the baseline.

This section now explores the growth in demand expected in PJM over the next five years. This gives the author's conjecture about how growth in demand most likely would met in the region.

15.1 Introduction to Forecast

Additional analysis gives a reasoned approach to estimates for the future. This forecast through year 2006 was conducted on an annual basis to determine the expected results under certain projected assumptions of future demand growth, energy needs, and fuel price. To accomplish this task, certain presumption elements of the analysis were projected out to the timeframe described. Several elements are needed for the forecast, including the following:

- Estimating future demand; here, estimates from PJM are used.
- Estimating future energy needs; here also, PJM estimates are used.
- Estimating future fuel price; here, Energy Information Agency estimates are scaled to the local circumstances at PJM.
- Estimating the fleet make-up year by year by:
  - ✔ Estimating unit retirements.
  - ✔ Estimating unit upgrades.
  - ✔ Estimating unit additions.

  and finally,
- Estimating the economics of gas turbines, combined cycles and coal units under these presumptions.

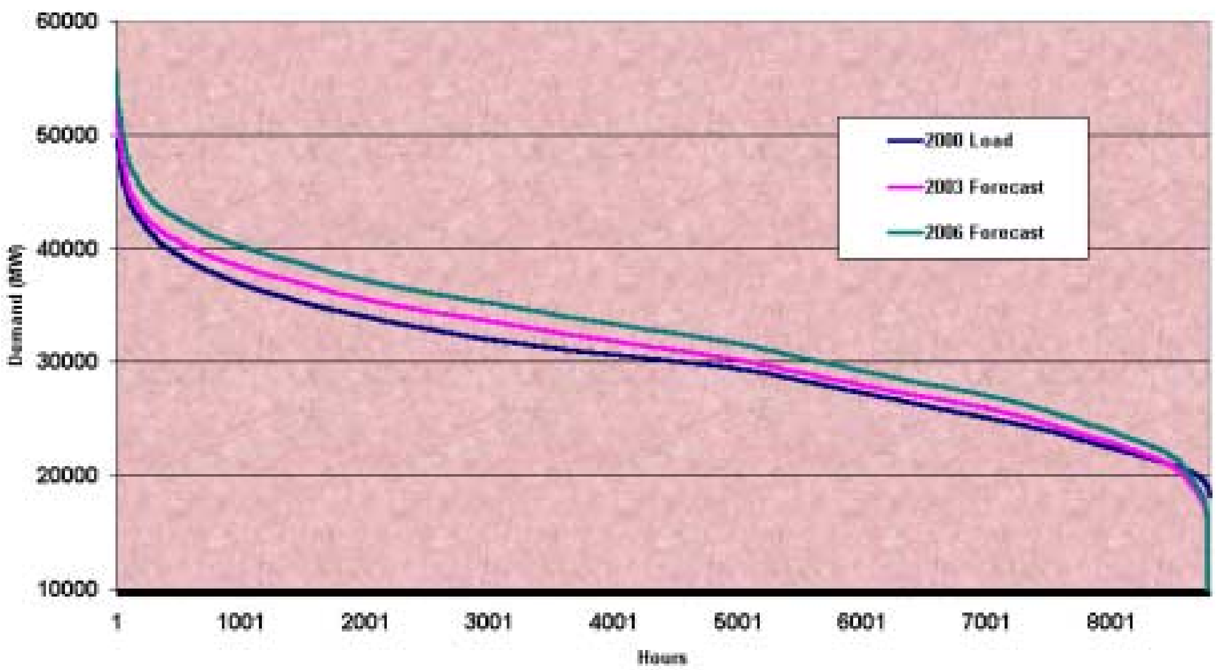
In the following sections, the elements forecasted out through 2006 are described, and in the final section, Section 15.8, "Comparison of Results (2000–2006)," beginning on page 15-96, the results of the analysis are shown for year 2006, the last year of the forecast.

15.2 PJM Forecast of Demand and Energy

PJM produces a fifteen year forecast of demand and energy on a monthly basis, and makes this information available to the public. Using that as a base, an hourly forecast of demand was developed for the six year period of the forecast. The actual demands for the year 2000 were used to develop this hourly forecast by taking the ratios of each hour to the peak hour in the month to determine the demand in the forecast for each hour.

On that basis, PJM is predicting that peak demand by the year 2006 will reach a level of approximately 56,000 MW's. This compares to a system peak of approximately 51,500 MW's experienced in 1999. Exhibit 15-1 shows the forecast load duration curve for the years 2000, 2003 and 2006.

Exhibit 15-1
PJM Load Forecast



Energy increased from 264,510 GWhrs to about 284,900 GWhrs or almost 8% in the six years of the forecast. Overall, PJM has an annual load factor of approximately 59%. This hourly forecast was then utilized in this analysis to develop the estimated prices used to determine the robustness of the various units likely to be added to the system.

15.3 Retirements, Upgrades and Additions

For each year of the forecast, the make-up of the fleet is estimated. This is done by the GEMSET team by taking the viewpoint of a generating company owner, presuming that all fleet make-up adjustments are based only on the economics implied by the projected prices from the prior year, and demand circumstances estimated for the future when any given plant project would be installed. That is for example, fleet adjustments for year 2001 demand are made on the basis of the potential financial return from electric sales in a price structure that was estimated for year 2000.

- **Retirements**. Units will not be retired unless the region has in excess of 20 percent reserve margin. Generation in excess of 20 percent reserve margin is retired on the basis of highest age highest production cost are first retired.

- **Upgrades**. Upgrades for environmental compliance and upgrades for economics are treated like addition decisions. Upgrade or new unit will be based on the best potential return on investment.

- **Additions**. Units already under construction will be completed, since the money is already sunk. Units in the queue, but not yet under construction will only be completed if still economical. New units will be added to the queue if more economical than units already in the queue; these are not assumed ready for construction till all units higher in the queue have either been built, or presumed withdrawn.

- **Do Nothing**. If no project is likely to give an adequate return in the evaluation year, nothing is done, and the existing fleet will meet demand.

These decisions were made for each year of the study. In this time frame, there was never a projected reserve margin above 20 percent, so it was assumed that no units were retired in the study period. The sections below describe the additions assumed.

15.4 PJM Fleet Additions

Currently, PJM has a queue system in which potential suppliers get in line to add generation to the system. There are various milestones that each supplier must meet in order to stay in line for their planned capacity additions. PJM updates their queue system on a semi-annual basis. As of the last update, over 40,000 MW's of new generation has been identified by PJM through 2005 and beyond. This update does not indicate when the unit will actually be added to the system, and when contacted, PJM indicated that this information was unavailable.

When publishing the information on the queue, PJM does indicate various levels obtained by the suppliers, including whether it is in-service, under construction, and various permitting levels. Based on that information, a number of units were identified as likely to be added to the system over the next five years, and are shown in Exhibit 15-2. This is only an estimate and should not be considered as a given for future analyses.

Exhibit 15-2
Forecasted Generation Addition Scenario for the PJM System For Years 2001 through 2006

Plant Name	Unit Type	Fuel	Summer kW
2001-1 gas unit	GT	NG	315,000
2001-2 gas unit	GT	NG	6,000
2001-3 gas unit	GT	NG	14,000
2001-4 gas unit	GT	NG	168,000
2001-5 gas unit	GT	NG	15,000
2001-6 gas unit	GT	NG	50,000
2001-7 gas unit	GT	NG	36,000
2001-8 gas unit	GT	NG	35,000
2002-1 gas unit	GT	NG	673,000
2002-2 gas unit	GT	NG	500,000
2002-3 gas unit	GT	NG	765,000
2003-1 gas unit	GT	NG	557,000
2003-2 gas unit	GT	NG	521,000
2003-3 gas unit	GT	NG	100,000
2003-4 gas unit	GT	NG	180,000
2003-5 gas unit	GT	NG	44,000
2004-1 gas unit	GT	NG	830,000
2004-2 gas unit	GT	NG	871,000
2004-3 gas unit	GT	NG	447,000
2004-4 gas unit	GT	NG	558,000
2004-5 gas unit	GT	NG	500,000
2005-1 gas unit	GT	NG	250,000
2005-2 gas unit	GT	NG	500,000
2005-3 gas unit	GT	NG	500,000
2005-4 gas unit	GT	NG	250,000
2006-1 coal unit	ST	COAL	500,000
2006-2 gas unit	GT	NG	500,000
2006-3 gas unit	GT	NG	250,000

As indicated in Exhibit 15-2 above, 28 units with a capacity of 9,935 MW's are expected to be added to the system through the early part of 2006. Of these units, all are natural gas fueled except for one 500 MW coal fired unit. These units were added to the baseline fleet of generating units for pricing purposes. When stacked, these new gas units would still sit behind the coal units with their lower threshold prices. The new gas units were thus expected to be dispatched only when load exceeded 30,000 MW's.

Even though adding coal units appears to make economic sense at year 2000 conditions, few coal units now exist in the PJM queue. It was thus presumed that the year 2000 price conditions would launch one coal project into the queue in year 2000, but it would take till year 2006 until the prior queue positions were exhausted, and this unit could be permitted and built. Other coal units are presumed to also have entered the queue in the following years 2001, 2002, 2003, etc. Many coal units thus are presumed under construction in the study 2000-2006 time frame, however, in the study timeframe, only this one new unit reaches completion to operate in the fleet. Later years, beyond 2006, would see the commissioning of added coal capacity in PJM as the presumed under-construction projects reach completion.

15.5 Fuel Forecast

After review of the analysis conducted for 2000, it is clear that fuel cost had a major impact on the potential of various units to be added to the PJM system. Therefore, for the forecast, it was decided to present two forecasts for natural gas and one for coal in assessing the potential of new gas turbines to be added to the system through 2006. In Exhibit 15-3, the annual fuel forecast utilized in this analysis is presented:

Exhibit 15-3
Fuel Forecast for PJM

Year	Coal Forecast	EIA Gas Forecast	Study Gas Forecast
2001	\$ 1.350 / 10^6 Btu	\$ 4.021 / 10^6 Btu	\$ 5.000 / 10^6 Btu
2002	\$ 1.364 / 10^6 Btu	\$ 3.573 / 10^6 Btu	\$ 5.150 / 10^6 Btu
2003	\$ 1.377 / 10^6 Btu	\$ 3.365 / 10^6 Btu	\$ 5.305 / 10^6 Btu
2004	\$ 1.391 / 10^6 Btu	\$ 3.339 / 10^6 Btu	\$ 5.464 / 10^6 Btu
2005	\$ 1.405 / 10^6 Btu	\$ 3.511 / 10^6 Btu	\$ 5.627 / 10^6 Btu
2006	\$ 1.419 / 10^6 Btu	\$ 3.579 / 10^6 Btu	\$ 5.800 / 10^6 Btu

15.5.1 Natural Gas

In Exhibit 15-3, two gas forecasts are presented. The first is the EIA forecast in which today's gas prices are expected to drop from their high of \$5.00/10^6 Btu at the end of 2000 to an average slightly above that for 1999. This drop is the price spike experienced in 2000 is due to expected increases in supplies for the foreseeable future. The second forecast presented is that actually utilized in the Study to reflect a continuation of the high gas prices experienced over the last year, and serves as a sensitivity test of PJM Threshold pricing with higher gas prices.

15.5.2 Coal

Coal pricing is expected to increase at slightly higher rates than what has happened over the past few years. The increase is moderate, resulting in an overall price increase of about $.07 over the six year period.

15.5.3 Other Fuels

All other fuels utilized in the PJM system were increased at the same rate as that for coal in order to maintain their current relationship when the fleet is stacked for pricing purposes.

15.6 Operating Expenses

In order to calculate the Threshold Bid Price and the resultant PJM Day-Ahead price, operating expenses were increased to reflect what is expected to be moderate increases in both fixed and consumable costs for all generating units. Exhibit 15-4 presents the forecasted increases in these operating costs.

Exhibit 15-4
Forecasted Operating Expenses by Unit Type.

	Coal		SSGT		CCGT	
Year	Fixed	Consumables	Fixed	Consumables	Fixed	Consumables
2001	27.34	0.0017	11.42	0.0003	16.32	0.00040
2002	27.88	0.00175	11.65	0.00031	16.65	0.00041
2003	28.44	0.0018	11.89	0.00032	16.98	0.00042
2004	29.01	0.00186	12.12	0.00033	17.32	0.00044
2005	29.59	0.00191	12.37	0.00034	17.67	0.00045
2006	30.18	0.00197	12.61	0.00035	18.02	0.00046

15.7 Scenario Options

To enable a reasonable comparison of new generation that may be added to PJM, or any other regional system, two forecast scenarios were selected to analyze the expected pricing required to support the investment in these technologies. The two scenarios selected are both based on the price of natural gas in the Northeast market for electric generation. One was the current forecast of natural gas by the Energy Information Administration, and the other, to serve as a sensitivity test, was a forecast selected to serve as the study basis. In the following sections, the results of the analysis are presented for review.

15.8 Comparison of Results (2000–2006)

For the forecasted period through 2006, it was decided to show the results for the last year of the short-term forecast. As follows, the results are presented in the same manner as previously described in earlier sections of the Report. That is, for each technology under consideration (simple cycle gas turbines, combined cycle turbines, and coal units) a price was determined for each level of potential capacity factors to ascertain the ability of that unit to meet expected rates of return and to cover all operating expenses.

15.8.1 EIA Gas Forecast

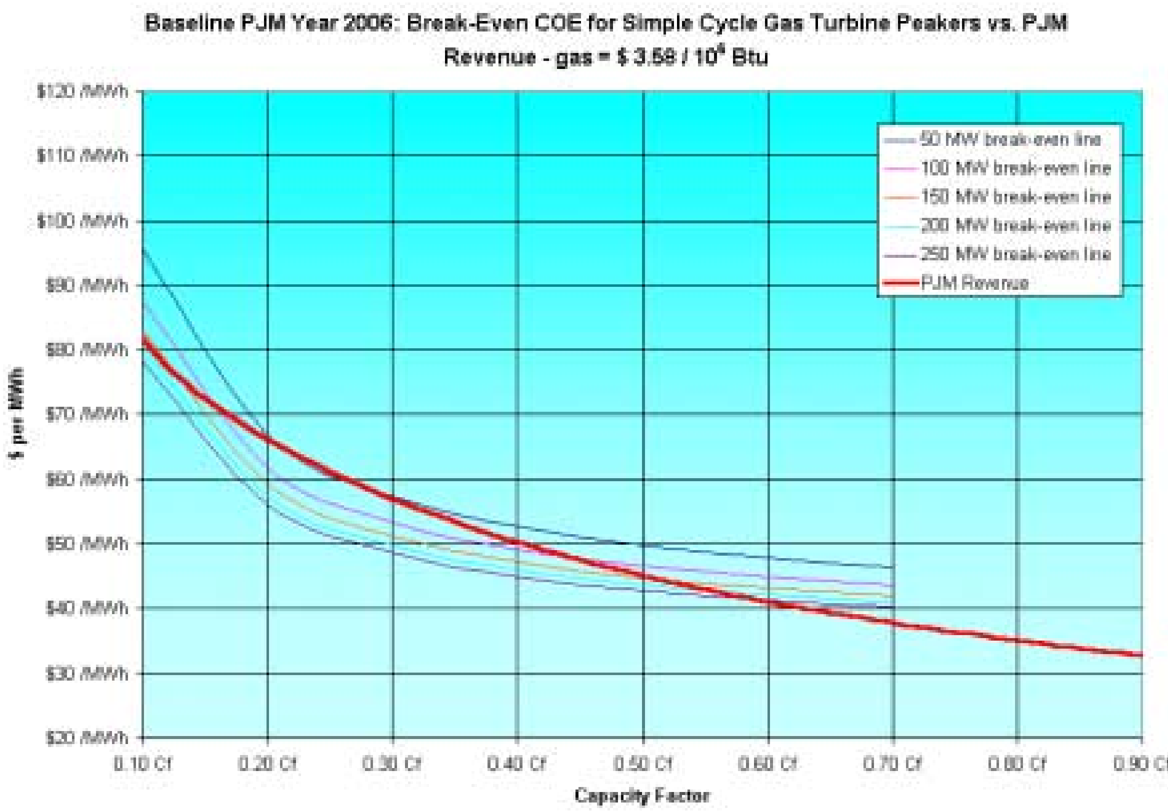
Exhibit 15-5 below, shows the ability of a simple cycle gas turbine, introduced by 2006 to exceed the calculated break-even point at varying levels of PJM prices. In the scenario of low gas prices, the SSGT exceeds the break-even price at the lower capacity factor levels since the cost of its Threshold Bid Price is below many of the other units in the fleet. At higher capacity factors, it is not competitive due to the lower day-ahead price at those high levels.

The results for a combined cycle unit under this forecast of natural gas prices are shown in Exhibit 15-6, which follows. In this case, the larger combined cycle units at higher capacity factors are certainly competitive in the PJM market under this natural gas price.

In the final comparison, coal units at larger sizes are also competitive under this low gas price forecast. The results are shown in Exhibit 15-7.

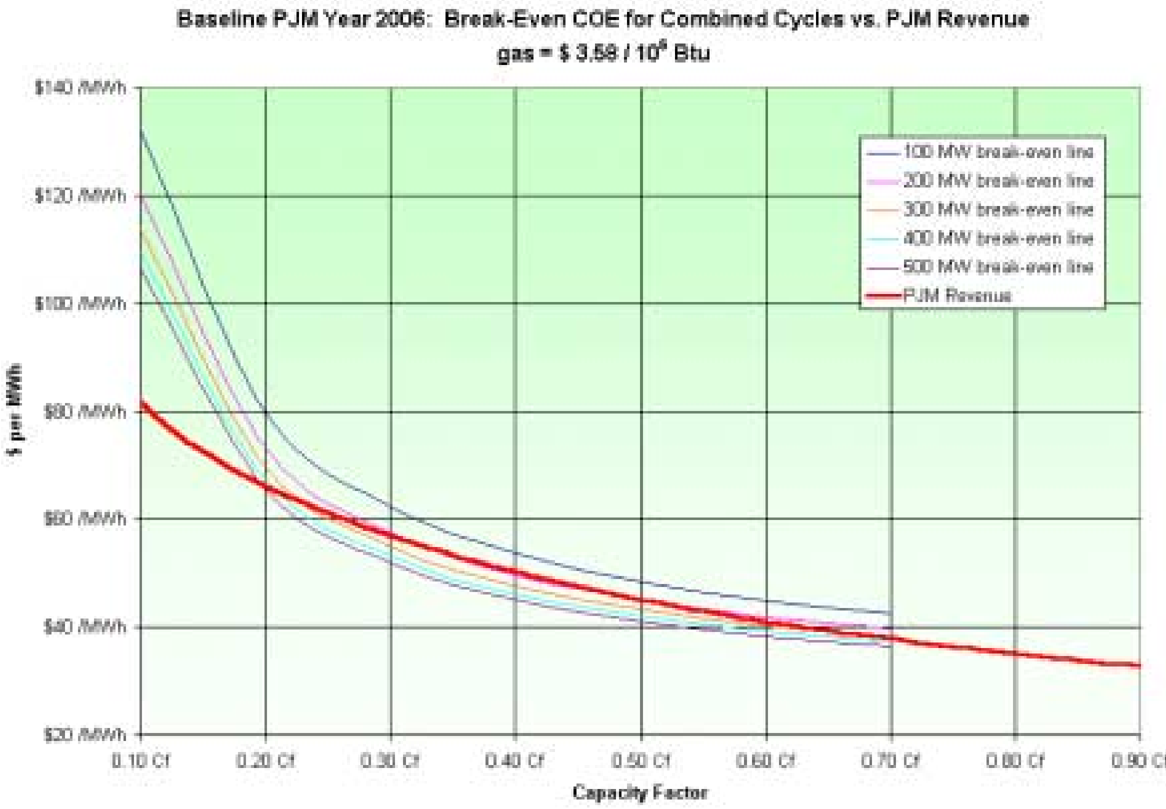
Exhibit 15-8, Exhibit 15-9, and Exhibit 15-10 indicated the corresponding graphs to the Baseline analysis for the three types of units for the Threshold Bid Price, the expected capacity factors at each size and the Breakeven COE versus the PJM day ahead prices. As expected, under the lower gas price forecast of EIA when compared against today's prices, the gas-fueled technologies are very competitive in the PJM region. Also, the larger coal units are likewise competitive when compared against the fleet bid prices and expected price to be received by the new units for their generation.

Exhibit 15-5
Year 2006 Break-Even Cost of Electricity for Simple Cycle in PJM Compared to Potential Revenue Under EIA Forecast



The results for a combined cycle unit under this forecast of natural gas prices are shown in Exhibit 15-6. In this case, the larger combined cycle units at higher capacity factors are certainly competitive in the PJM market under this natural gas price.

Exhibit 15-6
Year 2006 Break-Even Cost of Electricity for Combined Cycle in PJM Compared to Potential Revenue Under EIA Forecast



In the final comparison, coal units at larger sizes are also competitive under this low gas price forecast. The results are shown in Exhibit 15-7.

Exhibit 15-7
Year 2006 Break-Even Cost of Electricity for Coal Units in PJM Compared to Potential Revenue Under EIA Forecast

Exhibit 15-8
Comparison of Expected Threshold Bid Prices for SSGT, GTCC, and Coal Under EIA Forecast in 2006

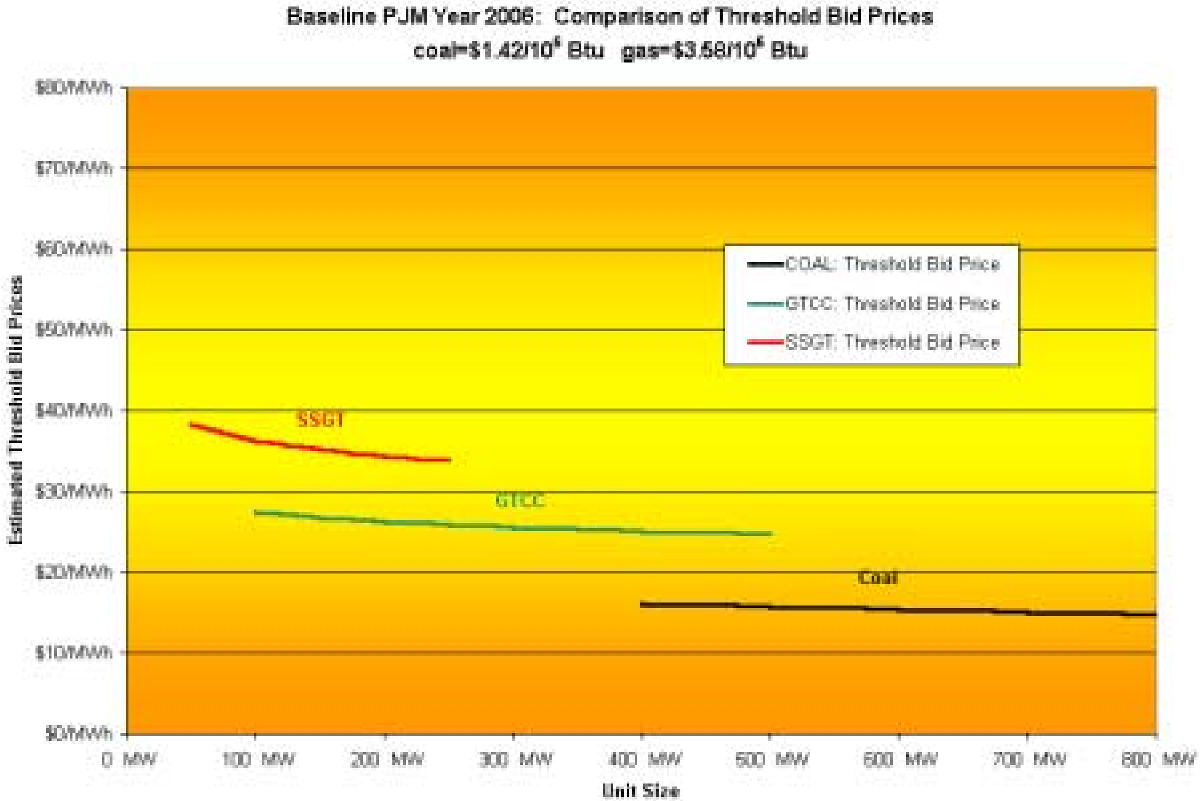


Exhibit 15-9
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under EIA Forecast in 2006

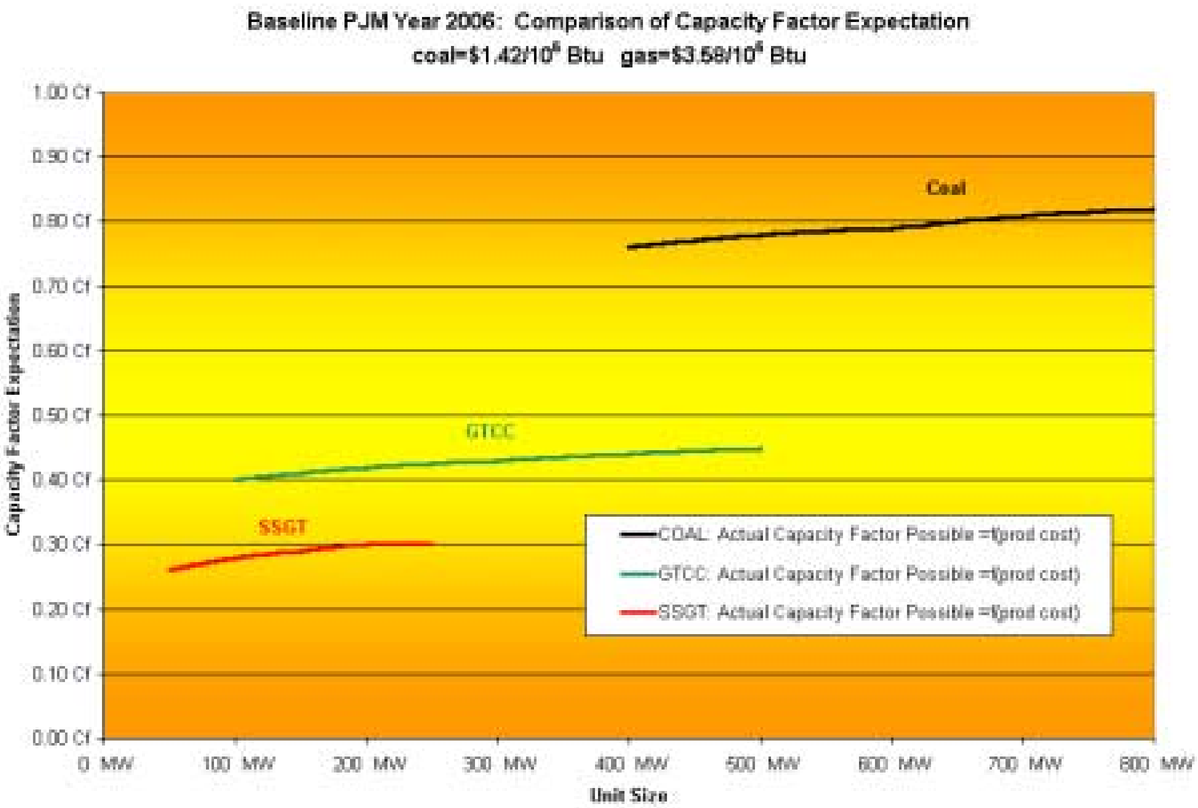
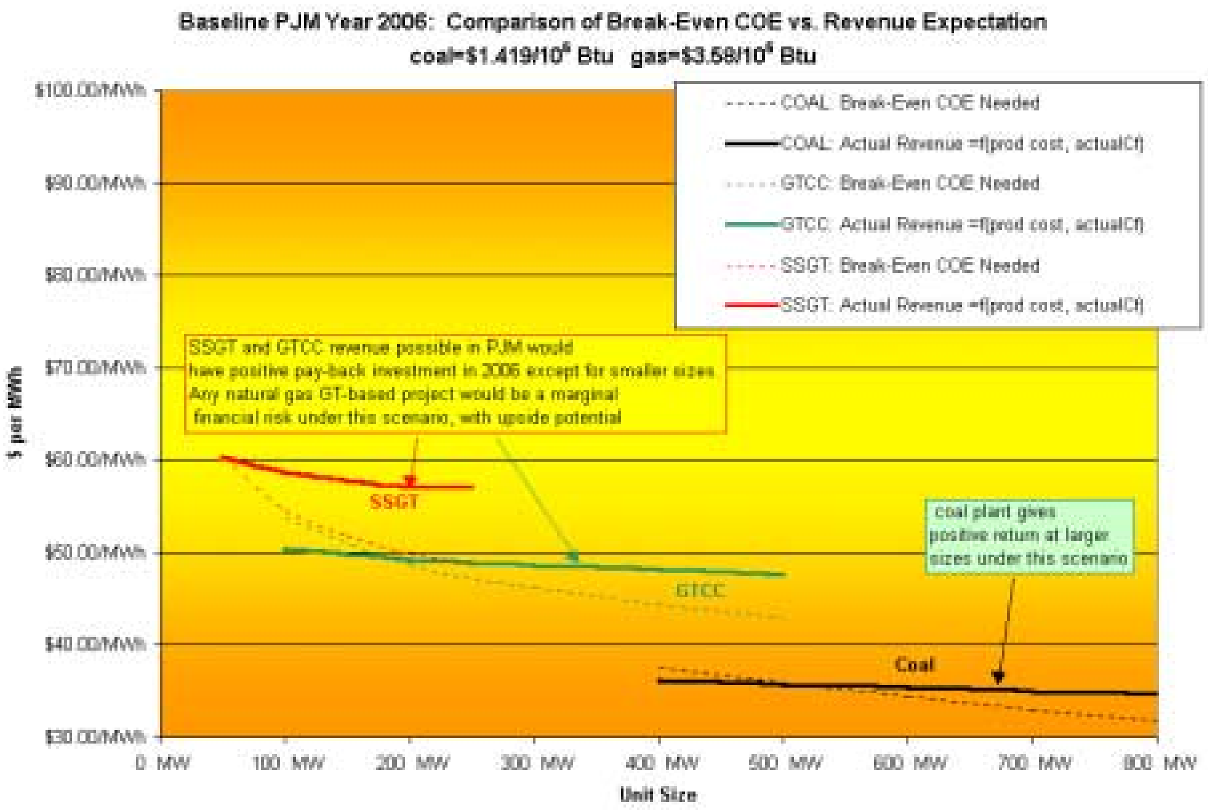


Exhibit 15-10
Comparison of EIA Forecast of SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2006 Projected PJM Day-Ahead Electric Price



15.8.2 Adjusted Gas Forecast

In order to compare the EIA forecast to one that has natural gas prices rising from today's price of $\$5.00/10^6$ Btu, a gas forecast was developed for study purposes, which by any standards, would be moderate compared against the rapid rise in prices over the last year. The results of that forecast are shown in the following Exhibits in the same manner as those shown for the EIA Forecast.

Exhibit 15-11, Exhibit 15-12, and Exhibit 15-13 provides the Break-even cost of electricity for each type of unit in 2006 under the higher gas price situation presentedin the study. As expected, the gas units do not compare as favorably in this forecast as that of EIA. There are certainly areas of operation in which they are competitive, but not as great as when natural gas prices are low in comparison.

Exhibit 15-14, Exhibit 15-15, and Exhibit 15-16 provide the details of Threshold bid price analyses, the expected capacity factors and the Break-even COE respectively.

Exhibit 15-11
Break-Even Cost of Electricity for Simple Cycle in PJM Compared to Potential Revenue Under the Study Sensitivity Gas Forecast

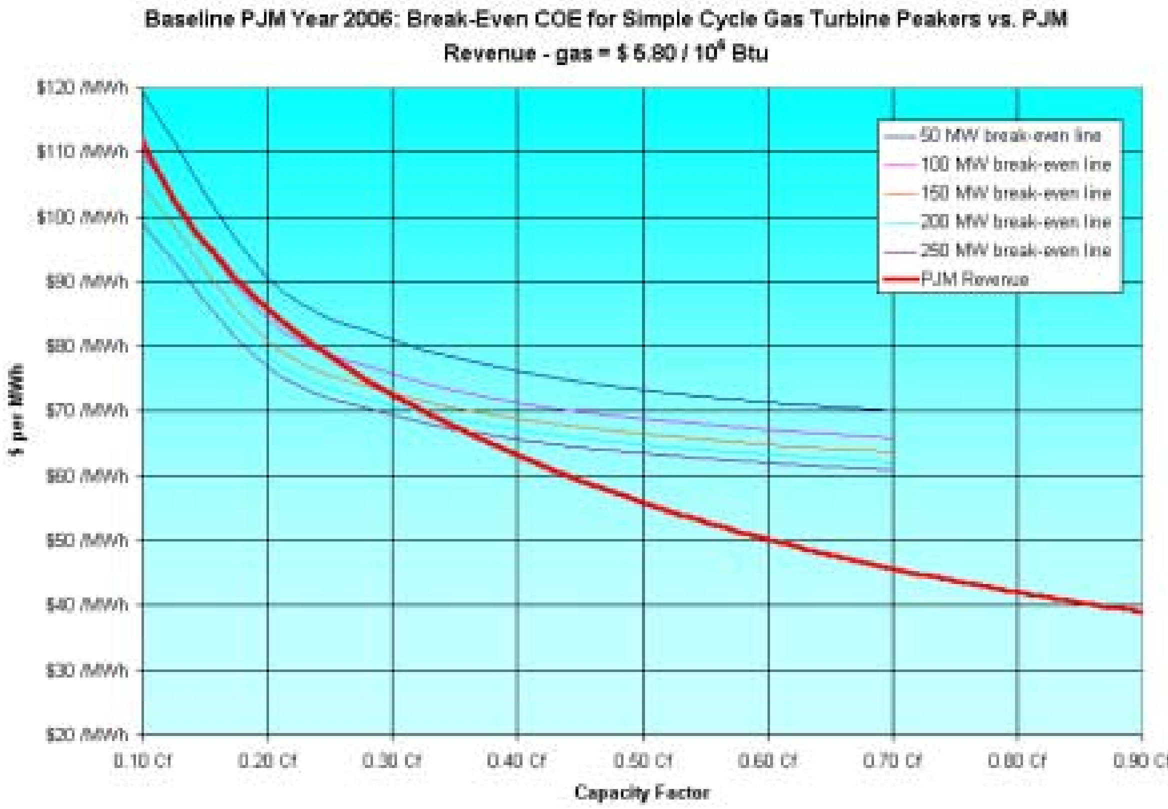


Exhibit 15-12
Break-Even Cost of Electricity for Combined Cycle in PJM Compared to Potential Revenue Under the Study Sensitivity Gas Forecast

Exhibit 15-13
Break-Even Cost of Electricity for Coal Units in PJM Compared to Potential Revenue Under the Study Sensitivity Gas Forecast

Exhibit 15-14
Comparison of Expected Threshold Bid Prices for SSGT, GTCC, and Coal Under the Study Sensitivity Gas Forecast in 2006

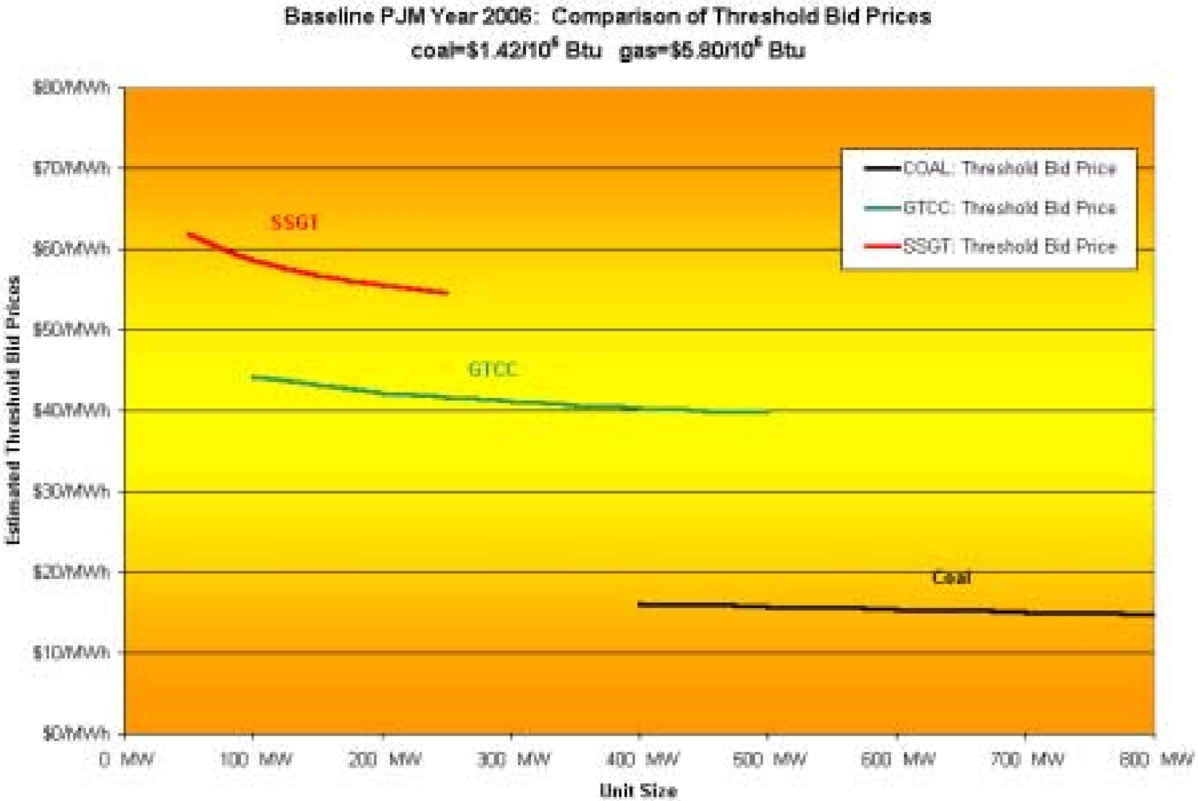


Exhibit 15-15
Comparison of Expected Capacity Factor for SSGT, GTCC, and Coal Under EIA Forecast in 2006

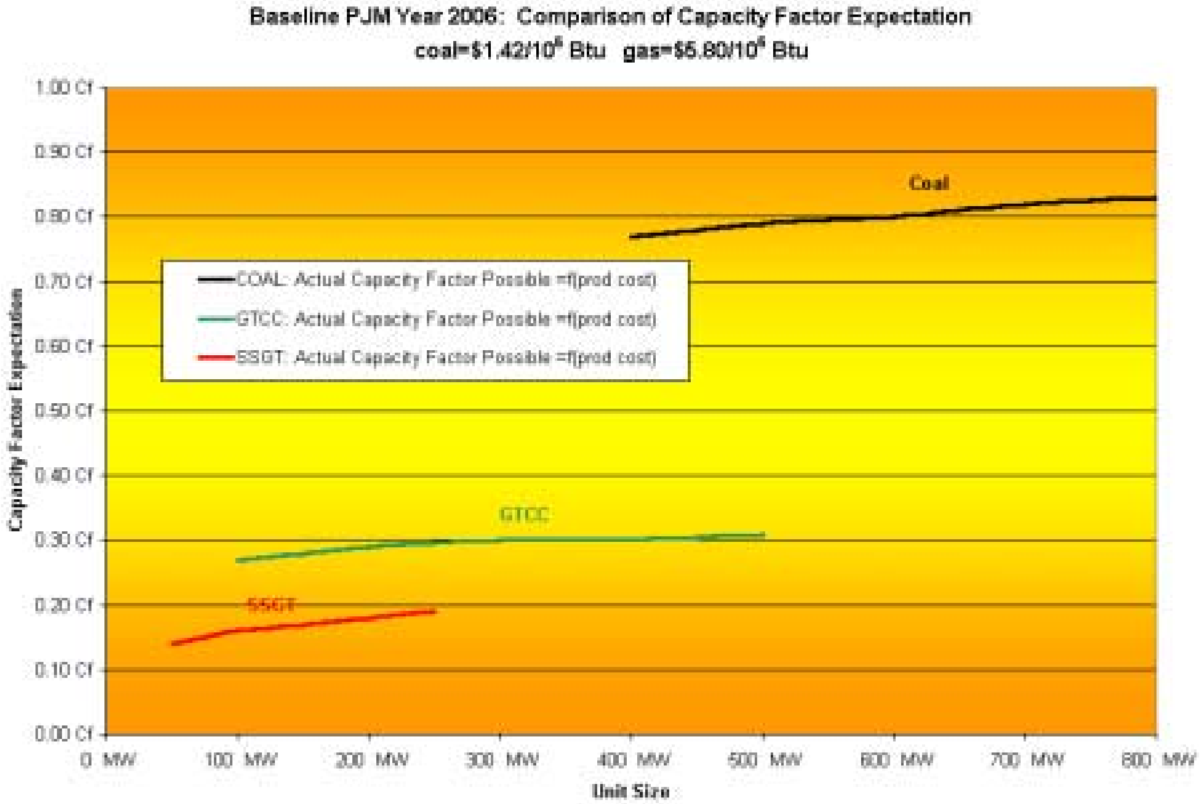
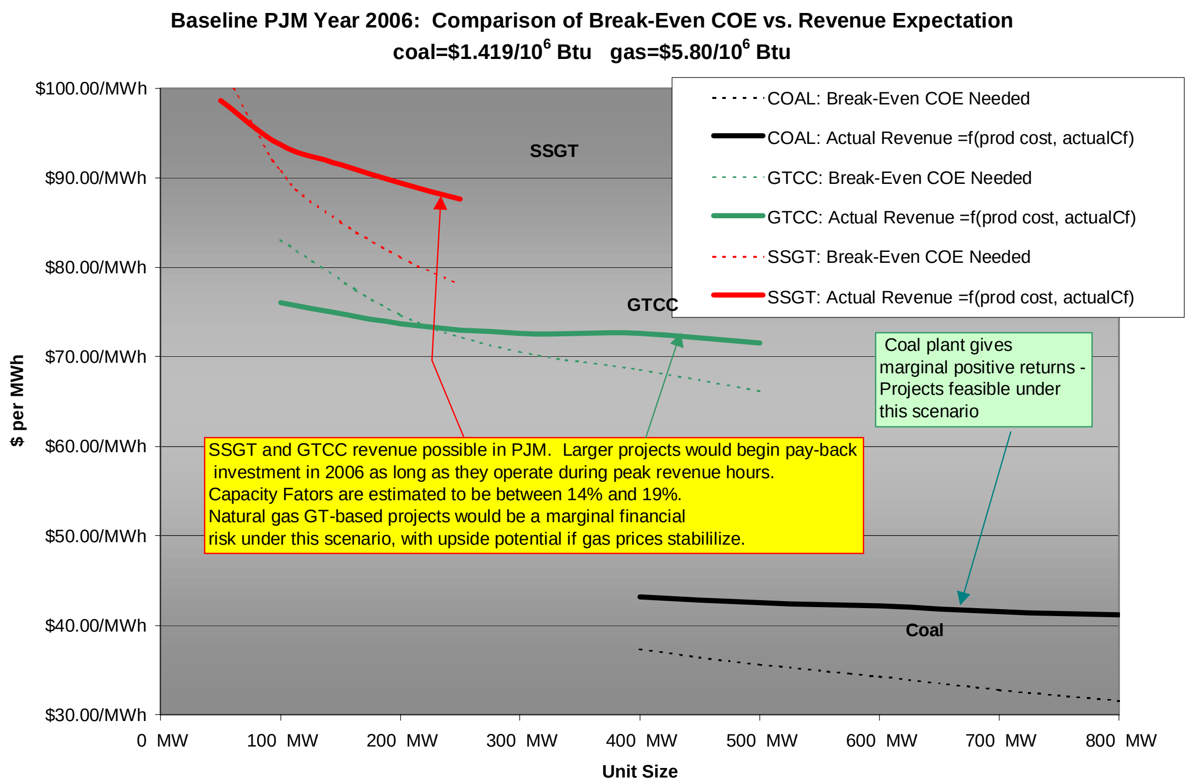


Exhibit 15-16
Comparison of Parsons Sensitivity Gas Forecast of SSGT, GTCC, and Pulverized Coal Project Break-Even COE versus Potential PJM Revenue With Year 2006 Projected PJM Day-Ahead Electric Price

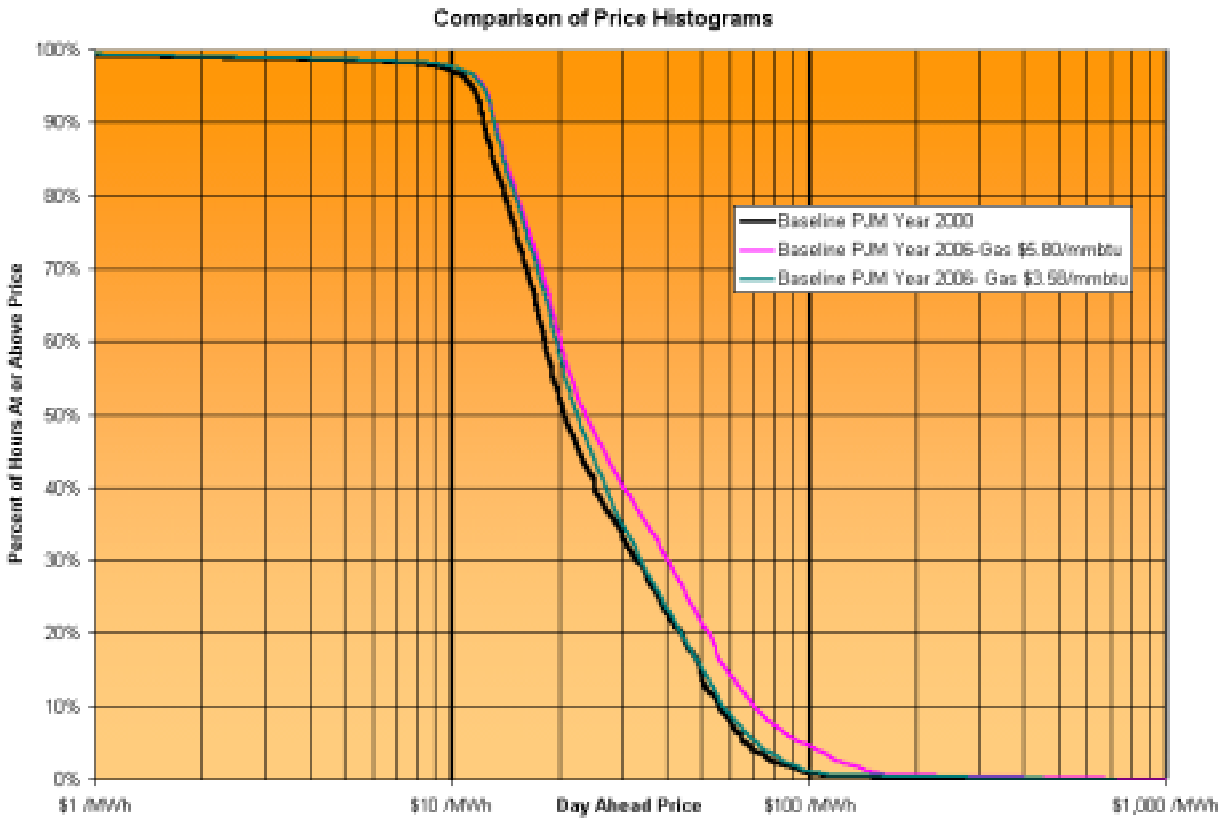


15.8.3 Summary of Forecasted Results

It is apparent from the projected forecast under both a high and low scenario that natural gas units will continue to play an important role in meeting the expected demands for all regions of the United States. Bid prices and expected market conditions leading to higher day-ahead pricing in PJM and other markets are realistic conclusions reached by this analysis. As new units are added, the market does seem to respond in a fashion that can be reasonably forecasted.

As an example of the day ahead pricing in PJM, the historical prices experienced in 2000 are compared against the projected pricing under the two new scenarios for 2006. As shown in Exhibit 15-17, the expected day ahead prices are obviously higher than that experienced in 2000. When natural gas prices are lower than prices in 2000, there is still a projected increase in prices due to higher costs in other areas. Likewise, when natural gas prices are higher than those for 2000, there is a greater increase in expected prices in PJM. It is those prices that are utilized in determining the ability of new gas units to be added to the fleet.

Exhibit 15-17
Price Histograms for PJM Under Historical and Projected Scenarios



While there is considerable risk in making decisions regarding the expected price of any commodity, this analysis tries to simulate a process in which suppliers act regarding their investment in new technologies. The actual magnitude of day ahead prices in PJM is subject to numerous factors beyond that which was analyzed as part of this assignment, and should not be used as the basis for significant investment decisions in generation additions.

16. References

The references used in preparing this document include the following:

[1] Weinstein, R.E. and Herman, A.A. GEMSET Regional Segmentation Analysis: Characterization of the PJM Region. Parsons Report No. EJ-2000-01. October 2000. Draft.

[2] Images from PJM Internet site: http://www.pjm.com. Downloaded 26 March 2001.

[3] Energy Information Administration. Gas Monthly. Table 24. "Average Price of Natural Gas Delivered to Electric Utility Consumers by State, 1998-2000." February 2001.

[4] Average of the year 2000 average cost to utility generators in New Jersey, Pennsylvania, Delaware, the District of Columbia and Maryland, reported to FERC, and tabulated by the Energy Information Administration. "Table 38. Receipts and Average Cost of Petroleum Delivered to Electric Utilities by Census Division and State."

[5] Calculated by Parsons based on 2nd Quartile production cost and capacity factor information downloaded from the Internet from the Nuclear Energy Institute web site. http:/www.nei.org.

[6] Energy Information Administration. Annual Energy Outlook 2001. DOE/EIA-0383. December 2000. Nuclear power Btu information taken from ("Table A2. Energy Consumption by Sector and Source," and kWh from "Table A8. Electricity Supply, Disposition, Prices, and Emissions."

[7] UDI Data Base